Cost of Service and Cost Allocation Report

Adopted 2015-2016 Rates

October 6, 2014

Seattle City Light

Contents

Executive Summary

The retail rates for 2015-2016 are aligned with the recently adopted six-year Strategic Plan Update for 2015-2020. The Strategic Plan establishes the revenue required to meet City Light's basic operations, capital improvements, and modest initiatives to improve utility services. Consistent with the Strategic Plan, the average rate increase is 4.2% for 2015 and 4.9% for 2016.

Table E.1 compares revenue requirements for 2014-2016. Note the revenue requirement shown here is higher than the revenue requirement found in the RRA because it treats rate discounts as an expense for unbundling purposes. Table 2.1 shows the relationship between the unbundled revenue requirement and the RRA revenue requirement.

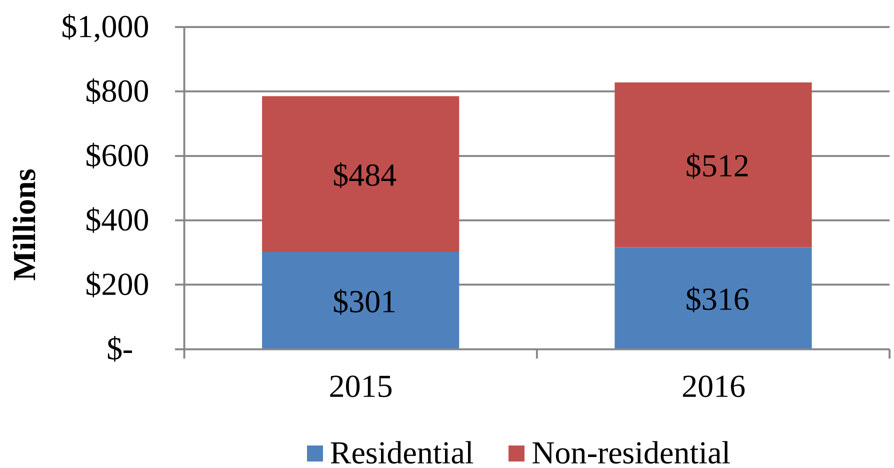
Table E.1: Revenue Requirement Changes

$M	2014	2015	2015 vs. 2014	2016	2016 vs. 2015
Energy	$504.5	$518.9	$14.4	$547.7	$28.7
Retail Services Costs	$336.4	$331.5	($4.9)	$340.8	$9.3
Net Wholesale Revenue Credit	($85.0)	($65.0)	$20.0	($60.0)	$5.0
Total	**$755.9**	**$785.4**	**$29.5**	**$828.5**	**$43.1**

- The 2015 revenue requirement increase is driven by energy costs, coupled with reduced dependence on net wholesale revenue, which offsets revenue that must be collected from retail customers.
- The main driver of the 2016 revenue requirement increase is again energy costs, and budgeted net wholesale revenue is also further reduced.

The second step in the rate-setting process, which is the subject of this report, is developing costs of service and allocating them to customer classes. **Figure E.1** below shows that 38% of the revenue requirement gets allocated to the residential customers and 62% to non-residential customers in each year.

Figure E.1: 2015 and 2016 Revenue Requirements Allocated Between Residential and Non-residential Customers ($M)



2015 Average Rate Impacts by Rate Class

The system average rate increase for 2015 is **4.2%**. This rate adjustment reflects the increased revenue requirement as well as lower system load expectations compared with what was assumed when setting the 2014 rates.

Table E.2: Summary of 2015 Rate Increases

	Total	Residential	Small	Medium	Large	High Demand
All areas	4.2%	3.8%	4.8%	3.9%	3.7%	5.6%
City of Seattle	4.5%	3.5%	4.6%	4.4%	5.6%	6.2%
Network	2.1%			2.7%	1.6%	
Shoreline	4.2%	3.9%	5.6%	4.2%	5.3%	
Tukwila	4.3%	5.2%	4.9%	4.1%	5.4%	3.4%
Other Suburbs	5.4%	5.6%	5.9%	3.7%	5.6%	

- Energy costs are the main determinant for differences in rate impacts among customer classes. Generally, higher energy consuming customer classes will see higher average rate impacts than lower consuming customer classes.
- While average network rates will remain significantly higher than non-network rates, average network rate increases are lower than those for non-network customers because of a decrease in distribution costs relative to 2014.
    - The network rate premium results from the cost of maintaining redundant distribution service and, therefore, higher reliability.
    - In 2013 steeply rising distribution costs caused average network rates to increase nearly three times the system average, so this change represents a return towards the historical differential.
- Suburban, Shoreline and Tukwila rate impacts vary from City averages due to new terms for renewed franchise agreements as well as differences in customer consumption patterns.

2016 Average Rate Impacts by Rate Class

The system average rate increase for 2016 is **4.9%.**

Table E.3: Summary of 2016 Rate Increases

	Total	Residential	Small	Medium	Large	High Demand
All areas	4.9%	5.0%	5.0%	4.6%	4.8%	6.1%
City of Seattle	5.2%	5.0%	5.0%	5.1%	5.6%	6.1%
Network	3.6%			3.4%	3.9%	
Shoreline	4.8%	4.9%	5.0%	5.1%	5.6%	
Tukwila	5.5%	4.9%	5.0%	5.1%	5.6%	6.1%
Other Suburbs	4.9%	4.9%	5.0%	5.1%	5.6%	

- Energy costs are the primary driver for the 2016 rate increase. Similar to 2015, higher energy consuming customer classes will see larger average rate impacts than lower consuming customer classes.
- As with 2015, network impacts are lower than average because of flat distribution costs.

Streetlights

- Significant rate increase percentages result from rising energy and capital costs (associated with light-emitting diode (LED) conversions), coupled with dropping streetlight load due to proliferation of high-efficiency LED streetlights.
- Despite the significant average rate increases, the General Fund streetlight bill (which represents about 85% of streetlights load) remains relatively stable because increasing rates are offset by lower energy consumption.

Table E.4: 2015-2016 Streetlight Rate Increases

	2014	2015	2016
Streetlight Rate Increase		11.3%	15.7%
Annual General Fund Streetlight Bill ($M)	$11.5	$11.2	$11.3

1. Introduction

The Cost of Service and Cost Allocation Report (COSACAR) details the costs of providing service to City Light customers and describes the methodology used to allocate revenue requirements to each rate class. Cost of service is the second step of a full three-step rate review process comprised of a revenue requirement analysis, a cost of service analysis, and a rate design.

Resolution 31351, adopted by the City Council in May 2012, establishes City Light's cost allocation principles. They are:

1. *Customer Payment Based on Cost of Service.* To encourage the efficient use of resources, rates should be based on the marginal cost of service to the customer and should reflect changes in the marginal cost over time.
2. *Equity.* Rates should reflect a fair apportionment of the different costs of providing service among groups of customers.
3. *Conservation Expense.* Since the City considers that conservation is a power resource, conservation expenditures shall be allocated to all customer rate classes.
4. *Utility Discount Program (UDP) Rates and Bill Payment Assistance Expense.* The costs of providing UDP rates and bill payment assistance to low-income residential customers shall be allocated to all customer classes.

The methodology for the Cost of Service study is the same as that used in the last full rate review (for 2013-2014 rates) and can be summarized in these three steps:

1. **Functionalization:** Revenue Requirements are allocated to functional cost categories that correspond to the services provided (energy, distribution, customer service), plus the subsidy for UDP customers and a credit for net wholesale power revenue. For Wires and Related Equipment and Customer Transformers only, the functionalized operating cost revenue requirements are separated into network and non-network components.

2. **Cost of Service and Allocation Factors:** Marginal costs for various service components (energy, transmission, substations, etc.) are calculated. The total cost of providing each of the services to each customer class in each year of the rate review is computed, with services valued at their respective marginal cost. The allocation factors are computed by dividing the total cost of each service for each customer class by the total cost of each service for all customers. This is done separately for network and non-network wires and transformers.

3. **Cost Allocation:** The allocation factors are used to divide the functionalized revenue requirements among customers for each of the two years. This is done separately for network and non-network wires and transformers. After this initial allocation of revenue requirements, adjustments reflecting franchise city agreements and Council policy directives are incorporated.

The rest of the report presents the details of the three steps described above to allocate the 2015 and 2016 revenue requirement among rate classes.

2. Functionalization

This section describes how the revenue requirement is assigned to functionalized categories such as energy, distribution, customer service and the UDP. The conversion process is also known as "unbundling" the revenue requirements. City Light has been unbundling the customer revenue requirement since the 1997-1998 rate review.

2.1. Results and Summary

The unbundling of revenue requirements for 2015-2016 follows the same methodology as that used in the 2013-2014 rate review. **Table 2.1** summarizes the functionalized revenue requirements for 2015 and 2016.

Table 2.1: Summary of Unbundled Revenue Requirements for 2015 and 2016

$ Millions	**2015**	**2016**
Total Energy	**$518.9**	**$547.7**
Power	$419.0	$439.0
Conservation	43.7	47.7
Transmission-Long Distance	56.2	60.9
Total Retail Services	**$331.5**	**$340.8**
Total Distribution	$254.6	$259.5
Transmission-In Service Area	15.1	15.8
Stations	40.3	41.1
Wires and Related Equipment	146.3	147.8
non-network	103.6	105.0
network	42.6	42.8
Transformers	27.5	27.7
non-network	13.6	13.7
network	13.9	14.1
Meters	14.9	15.7
Streetlights/Floodlights	10.5	11.3
Customer Accounts & Services	62.4	64.9
Rate Discounts (UDP)	14.5	16.4
Subtotal	**$850.4**	**$888.5**
Net Wholesale Revenue Credit	-$65.0	-$60.0
Unbundled Revenue Requirement	**$785.4**	**$828.5**
Rate Discounts	-11.3	-12.9
Revenue Requirement (Strategic Plan)	$774.1	$815.6

The Unbundled Revenue Requirement does not match the Revenue Requirement published in the Strategic Plan; it is higher because it treats rate discounts as an expense in order to allocate them to other customer classes.

The cost allocated to each functionalized category is calculated by adding net direct expenses and various assigned/allocated expenses. Assigned/allocated expenses are: Depreciation and amortization net of capital contributions, interest; administration and general (A&G) expenses, revenue taxes and county payments; and net income.

Table 2.2 details dollars assigned to each functional category for 2015 and 2016. Each functional category is discussed individually in the following sections.

Table 2.2: Unbundled Revenue Requirements 2015-2016

Functions	**2015**		**2016**	
	Dollars	**$/MWh**	**Dollars**	**$/MWh**
ENERGY				
Power				
Direct Expenses:				
Generation O&M	$38,825,362		$40,423,591	
Long-Term Purchased Power	229,177,066		234,981,953	
Power-Related Wholesale Purchases	17,690,848		9,000,000	
Other Power Costs	13,813,992		14,477,506	
Article 49 Sales to Pend Oreille County	-1,854,024		-1,897,903	
Sales from Priest Rapids	-5,754,528		-5,756,978	
Seasonal Exchange Delivered	991,092		929,673	
SMUD Exchange Revenue	-4,854,595		-5,269,283	
Power-Related Wholesale Sales	-27,102,038		-18,590,566	
Subtotal	260,933,174		268,297,993	
Depreciation and Amortization:				
Amortization of Hydro Project Mitigation	6,309,603		7,240,830	
Amortization of High Ross Contract	347,400		347,404	
Plant Depreciation	20,177,510		20,788,444	
Subtotal	26,834,513		28,376,677	
Capital Contributions and Grant Revenues	0		0	
Interest	22,580,893		25,241,874	
Administration and General	15,090,642		15,764,492	
Revenue Taxes and Payments in Lieu of Taxes:				
Revenue Taxes	43,391,663		46,003,450	
Whatcom County Contract Payments	1,027,657		1,051,470	
Pend Oreille County Contract Payments	2,573,365		1,774,735	
Payments to Concrete School District	30,000		30,000	
Subtotal	47,022,685		48,859,655	
Net Income (Contribution to Equity)	26,671,540		29,155,574	
Net Income (Risk Management)	19,899,426		23,347,749	
Total Power	**$419,032,873**	**$43.80**	**$439,044,015**	**$45.68**
Conservation				
Direct Expenses:				
Conservation	$5,130,921		$5,269,468	
Operating Fees (Lighting Lab)	-300,000		-300,000	
Green Up and Community Solar Retail Revenue	-1,092,949		-1,119,609	
Subtotal	3,737,972		3,849,860	
Depreciation and Amortization:				
Amortization of Programmatic Conservation	20,521,659		22,345,696	
BPA Payments for Conservation	-913,368		-913,365	
Plant Depreciation	200,687		206,763	
Subtotal	19,808,978		21,639,095	
Interest	6,908,609		7,722,734	
Administration and General	948,630		990,989	
Revenue Taxes	4,141,000		4,620,467	
Net Income (Contribution to Equity)	8,160,139		8,920,128	
Total Conservation	**$43,705,328**	**$4.57**	**$47,743,273**	**$4.97**

(Table 2.2 continued, page 2)

Functions	2015		2016	
	Dollars	$/MWh	Dollars	$/MWh
Transmission-Long Distance				
Direct Expenses:				
Transmission O&M	$7,593,618		$8,116,569	
Wheeling	38,473,845		39,648,655	
Transmission Services	-6,012,580		-4,422,349	
Transmission Attachments & Cell Sites	-974,018		-974,018	
Subtotal	39,080,864		42,368,856	
Depreciation and Amortization:				
Amortization of Puget Stillwater Substation	$99,286		$99,286	
Plant Depreciation	2,901,963		2,989,821	
Subtotal	3,001,249		3,089,107	
Capital Contributions and Grant Revenues	0		0	
Interest	2,362,156		2,640,517	
Administration and General	2,503,293		2,615,074	
Taxes:				
Oregon Tax on 3rd AC Intertie	245,000		245,000	
Revenue Taxes	6,226,488		6,887,303	
Subtotal	6,471,488		7,132,303	
Net Income (Contribution to Equity)	2,790,073		3,049,923	
Total Transmission Long Distance	**$56,209,123**	**$5.88**	**$60,895,780**	**$6.34**
TOTAL ENERGY	**$518,947,324**	**$54.24**	**$547,683,068**	**$56.98**
RETAIL SERVICES				
Transmission-In Service Area				
Direct Expenses:				
Transmission O&M	$4,547,118		$4,856,224	
Transmission Attachments & Cell Sites	-575,722		-575,722	
Subtotal	3,971,396		4,280,502	
Plant Depreciation	3,227,339		3,325,048	
Capital Contributions and Grant Revenues	-1,532,203		-1,991,244	
Interest	3,030,286		3,387,380	
Administration and General	1,447,691		1,512,336	
Revenue Taxes	1,337,669		1,420,348	
Net Income (Contribution to Equity)	3,579,238		3,912,586	
Total Transmission In Service Area	**$15,061,416**	**$1.57**	**$15,846,955**	**$1.65**
Distribution-Stations				
Direct Expenses:				
Distribution O&M-Stations	$17,757,915		$18,100,272	
Gain on Sale of Distribution Assets*	-1,023,880		-1,048,511	
Subtotal	16,734,035		17,051,761	
Plant Depreciation	5,630,742		5,801,230	
Capital Contributions and Grant Revenues	-3,033,706		-3,942,590	
Interest	3,046,185		3,405,155	
Administration and General	10,042,522		10,444,351	
Revenue Taxes	4,274,917		4,425,562	
Net Income (Contribution to Equity)	3,598,018		3,933,117	
Total Distribution-Stations	**$40,292,713**	**$4.21**	**$41,118,586**	**$4.28**

(Table 2.2 continued, page 3)

Functions	2015		2016	
	Dollars	$/MWh	Dollars	$/MWh
Distribution-Wires and Related Equipment				
Direct Expenses:				
Distribution O&M-Wires and Related Equipment	$35,846,895		$36,616,765	
Property Rental Income	-2,581,350		-2,643,446	
Revenue from Damage	-1,181,399		-1,209,818	
Other O&M Revenue	-8,291,990		-8,498,677	
Construction (Installation) Charge Revenue	-1,000		-1,000	
Pole Attachment Revenue	-2,674,867		-2,674,867	
Distribution Capacity Charge Revenue	-223,343		-228,418	
Power Factor Revenue	-2,950,806		-3,022,482	
Subtotal	17,942,140		18,338,057	
Plant Depreciation	56,102,858		57,801,549	
Capital Contributions and Grant Revenues	-30,226,844		-39,282,667	
Interest	34,768,330		38,865,506	
Administration and General	14,345,652		14,919,957	
Revenue Taxes	12,254,162		12,244,955	
Net Income (Contribution to Equity)	41,066,794		44,891,521	
Total Distribution-Wires and Related Equipment	**$146,253,092**	**$15.29**	**$147,778,878**	**$15.38**
Distribution-Transformers				
Direct Expenses:				
Distribution O&M-Transformers	$3,640,064		$3,713,180	
Credits for Customer-Owned Transformers	375,941		384,251	
Subtotal	4,016,005		4,097,431	
Plant Depreciation	10,736,786		11,061,876	
Capital Contributions and Grant Revenues	-5,784,717		-7,517,792	
Interest	6,665,473		7,450,947	
Administration and General	1,697,847		1,766,467	
Revenue Taxes	2,285,342		2,277,486	
Net Income (Contribution to Equity)	7,872,958		8,606,201	
Total Distribution-Transformers	**$27,489,694**	**$2.87**	**$27,742,616**	**$2.89**
Distribution-Meters				
Distribution O&M-Meters	$4,099,768		$4,174,275	
Plant Depreciation	2,908,263		2,996,320	
Interest	1,860,627		2,079,887	
Administration and General	2,395,505		2,490,432	
Revenue Taxes	1,485,308		1,586,090	
Net Income (Contribution to Equity)	2,197,689		2,402,369	
Total Distribution- Meters	**$14,947,160**	**$1.56**	**$15,729,373**	**$1.64**
Distribution-Streetlights/Floodlights				
Distribution O&M-Lights	$3,356,155		$3,843,387	
Plant Depreciation	3,129,078		3,223,820	
Capital Contributions and Grant Revenues	-1,685,870		-2,190,949	
Interest	1,662,435		1,858,340	
Administration and General	1,116,444		1,298,416	
Revenue Taxes	999,278		1,085,186	
Net Income (Contribution to Equity)	1,963,594		2,146,472	
Total Distribution-Streetlights/Floodlights	**$10,541,113**	**$1.10**	**$11,264,673**	**$1.17**
SUBTOTAL DISTRIBUTION	**$239,523,773**	**$25.04**	**$243,634,126**	**$25.35**
SUBTOTAL DISTRIBUTION + IN SERVICE AREA TRANSMISSION	$254,585,189	$26.61	$259,481,081	$27.00

(Table 2.2 continued, page 4)

Functions	2015		2016	
	Dollars	**$/MWh**	**Dollars**	**$/MWh**
Customer Accounts and Services				
Direct Expenses:				
Customer Accounting and Advisory O&M	$41,378,558		$42,677,087	
Late Payment Fees	-5,270,882		-5,443,920	
Account Change Fee Revenue	-1,267,001		-1,279,671	
Revenue from Current Diversion	0		0	
Revenue from Miscellaneous Rentals	-150,000		-150,000	
Revenue from Reconnect Charges	-1,000,000		-1,000,000	
Subtotal	33,690,675		34,803,495	
Plant Depreciation	3,600,916		3,709,945	
Interest	386,473		432,016	
Administration and General	17,021,204		17,781,261	
Revenue Taxes	7,212,722		7,663,258	
Net Income (Contribution to Equity)	456,485		498,999	
Total Customer Accounts and Services	**$62,368,476**	**$6.52**	**$64,888,974**	**$6.75**
Utility Discount Program				
Direct Expenses:				
Utility Discount Program O&M	$884,049		$911,787	
Rate Discount	11,318,737		12,918,757	
Bill Payment Assist. from Low-Income Acct.	299,546		306,631	
DHS Administration Payments	0		0	
Account Change Fee Waiver	41,202		42,232	
Late Payment Fees	-178,945		-184,820	
Subtotal	12,364,590		13,994,587	
Plant Depreciation	76,857		79,184	
Interest	8,249		9,221	
Administration and General	363,295		379,517	
Revenue Taxes	1,689,539		1,953,752	
Net Income (Contribution to Equity)	9,743		10,650	
Total Utility Discount Program	**$14,512,272**	**$1.52**	**$16,426,911**	**$1.71**
TOTAL RETAIL SERVICES	**$331,465,937**	**$34.65**	**$340,796,967**	**$35.46**
SUBTOTAL RETAIL CUSTOMER REVENUE REQUIREMENT BEFORE CREDIT	**$850,413,261**	**$88.89**	**$888,480,034**	**$92.44**
CREDIT FOR NET WHOLESALE POWER SALES	**-$65,000,002**		**-$60,000,000**	
TOTAL REVENUE REQUIREMENT	**$785,413,259**	**$82.09**	**$828,480,034**	**$86.20**

2.2. Direct Expenses

Direct expenses are O&M expenses that are directly incurred in providing City Light's services under each functional category. They are modified by revenue offsets where appropriate.

2.2.1. Energy

Power Expenses: Direct generation expenses include the costs of running City Light's seven hydroelectric plants (Boundary, Ross, Diablo, Gorge, Cedar Falls, Newhalem, and South Fork of the Tolt), as well as system control and dispatch expenses. Direct purchased power expenses include City Light's costs associated with long-term power contracts including Bonneville Power Administration (BPA) Slice and Block, Lucky Peak, High Ross, Grand Coulee Project Hydroelectric Authority, Stateline Wind Project, and others.

Other direct expenses and offsets in this category include:

- Basis purchases and sales;
- Other power costs, such as expenses associated with City Light's automated system control center, checking the metering apparatus associated with power purchases, and contract and environmental expenses;
- Other power revenues, such as the sale of capacity and RECs (environmental benefits of energy generated from green resources), sales to Pend Oreille Public Utility District under Article 49 of the Boundary Project license, sales from the Priest Rapids Project (per contracts with Grant County PUD No. 1), and seasonal energy exchange deliveries.

Conservation: City Light policy is to treat conservation as an energy resource. Costs of installed conservation measures are amortized over 20 years; therefore, direct conservation expenses include only annual planning, management, and customer information and assistance costs. Revenues received from operation of the lighting lab are netted against these expenses. Revenues received from retail customers who make voluntary payments in support of City Light's Green Up and Community Solar programs are also netted against direct conservation expenses because they offset the expense of acquiring local renewable energy resources.

Long-Distance Transmission: Transmission O&M expenses are incurred for either long-distance transmission (Energy) or in service area transmission (Retail Services). In most cases, Federal Energy Regulatory Commission (FERC) account names designate the nature of the transmission expense. However, a few expense categories (e.g., supervisory and engineering, load dispatching, and other expenses related to other sub-functions) must be allocated between the two transmission sub-functions; averaged 2011-2012 transmission labor hour percentages are used for this purpose. Overall, approximately 62.9% of forecasted transmission O&M expense is allocated to long-distance transmission, while 37.1% goes to in service area transmission. The long-distance transmission costs in Table 2.2 do not include Puget Intertie and Puget Stillwater Substation amortization, since these amounts are categorized as amortization (see Section 2.2).

Direct expenses of long-distance transmission include the costs of operating and maintaining City Light's owned transmission facilities, payments for the operation and maintenance of the utility's share of BPA's Third AC Intertie, and payments to other entities for transmitting power across their high voltage lines (called "wheeling").

Owned transmission expenses include transmission load dispatching, switching stations, inspecting and testing lines, and engineering. Owned long-distance transmission facilities include lines that connect City Light's service territory to the Skagit, Cedar Falls, and Tolt projects, as well as BPA connections. Wheeling payments include payments to BPA and other utilities for transmission of power from Boundary, Lucky Peak, Grand Coulee, and other facilities.

Transmission expenses are offset by revenues from:

- Transmission services, which are assigned to the long-distance sub-function. These costs are primarily associated with wheeling Skagit power through Snohomish PUD territory and City Light's contractual reassignment of its share of the Third AC Intertie to third parties.
- A portion of rental revenue for transmission line attachments and cellular antenna sites, which are allocated to both transmission sub-functions in accordance with the average 2011-2012 O&M ratio.

2.2.2. Retail Services

In Service Area Transmission: Direct expenses of in service area transmission include transmission load dispatching, switching stations, inspecting and testing lines, and engineering. City Light transmission facilities include the Bothell and Beacon Hill switching stations, the Covington and Talbot Hill substations, Maple Valley to South Substation and South Renton to Duwamish substation facilities, Duwamish to Delridge and Delridge to South substation facilities, Bothell to Seattle lines, all underground transmission lines and equipment, and a few smaller transmission substations and lines. These expenses are reduced by allocated rental revenues from transmission line attachments and cellular antenna sites.

Distribution: Direct distribution expenses cover the O&M costs of the Department's distribution system (i.e., the lower voltage lines and associated equipment that bring energy to individual customers), and are comprised of costs associated with distribution load dispatching and substations, overhead and underground lines, public lighting, meters, poles, vaults, ducts, and transformers.

Direct distribution expenses are allocated among five sub-functions: stations, wires and related equipment (wires), transformers, meters, and streetlights/floodlights (lights). The allocation of forecasted distribution O&M expenses among these five sub-functions prior to revenue offsets is based on actual 2011 and 2012 expenses and labor hours recorded in FERC accounts.

Most distribution FERC accounts carry titles that relate directly to the five distribution sub-functions. However, some accounts must be allocated to more than one sub-function on the basis of 2011 and 2012 labor hours. Load dispatching is allocated across stations, wires, and transformers. General distribution expenses in the categories of supervision and engineering, apprenticeship programs, safety, and tools are allocated to all sub-functions. Other miscellaneous distribution expense is allocated to all sub-functions excluding lights. **Table 2.3** summarizes percentages of direct distribution expenses that were allocated to the five distribution sub-functions.

Table 2.3: Direct Distribution Expenses Allocation Percentages 2015-2016

Distribution Sub-Function	2015	2016
Stations	27.4%	27.2%
Wires	55.4%	55.1%
Transformers	5.6%	5.6%
Meters	6.3%	6.3%
Lights	5.2%	5.8%

Three distribution sub-functions have additional offsets to O&M expense:

- Stations include an offset for gains on the sale of minor surplus distribution properties.
- Wires include an offset for revenues from property rental and damages, construction charges, pole attachment, power factor charges, reserved distribution capacity charges, and other sundry charges (e.g., equipment maintenance).
- Transformers include an additional expense for transformer investment discounts, which are credited to customers who supply their own transformers.

Distribution expenses allocated to lights are not allocated based on the entire 2011 and 2012 expenses, because LED conversion is expected to significantly reduce future O&M associated with lights, making the historical amounts an inaccurate indicator of future expense. Based the forecasted LED conversion rate, O&M allocated to lights was reduced by 48% in 2015 and 42% in 2016, and this expense was allocated across the remaining distribution sub-functions.

Customer Accounts and Services: Direct expenses in this category cover meter reading, records and collections, uncollectible accounts, and customer information and assistance (except amounts related to conservation and UDP). These expenses are reduced by revenue from late payment fees and account change fees, miscellaneous equipment rentals, and reconnect charges.

Utility Discount Program (UDP): City Light provides reduced electric rates, bill payment assistance, and fee waivers for qualified low-income residential customers. Direct expenses for this category include estimated O&M expenses related to UDP activities charged under customer accounts and services (e.g., credit, collections and the work of customer service representatives). The O&M applicable to the UDP is estimated based on 2012 labor hours devoted to UDP activities as a percentage (2.09%) of total labor hours in the customer accounts and services function for that year. Other elements of the revenue requirement included in UDP direct expense are revenues foregone for the rate discount and account change fee waivers, contributions from City Light's UDP account for bill payment assistance, and administrative costs paid to the Human Services Department (HSD). Income from late payment fees offsets the foregoing expenses.

2.3. Assigned and Allocated Expenses

Depreciation: Assets are depreciated over their useful lives and the associated expense is charged against income each year. Depreciation categories include production plant, transmission plant, distribution plant, and general plant. For future years, the projected depreciation amount includes the depreciation associated with forecasted additions to capital plant. Depreciation amounts associated with production, transmission and distribution plant are assigned directly to these categories. Depreciation amounts related to transmission and distribution are further disaggregated into unbundled categories based on the 2012 depreciation provisions in City Light's accounting records.

General plant depreciation is allocated to production and purchased power (power), conservation, transmission, distribution, customer accounts and services, and the UDP based on categorization of the items in the general plant depreciation schedule. General plant assignments or allocations include:

- Microwave communications equipment and Skagit general plant – assigned to production because the microwave equipment is used generally to control generation and because the Skagit project is a series of generation facilities.
- System Control Center – allocated to production, purchased power, transmission and distribution according to 2012 labor hour percentages.
- Customer service software (Banner and automated meter reading) – assigned to customer accounts and services.
- Distribution apprenticeship and training sites, software and monitoring equipment, distribution equipment – assigned to distribution.
- Stores, shops, pole yards, tools, commercial transportation and garage equipment, materials management systems and laboratory equipment – allocated to production, transmission and distribution according to 2012 labor hour percentages.
- Office buildings and furniture, passenger cars, internally developed software, Summit financial system, and data processing, communications and miscellaneous equipment – allocated to all functions based on 2012 non-A&G labor hours, on the assumption that depreciation expense for these items is analogous to A&G expenses, for which the non-A&G labor hour allocation procedure was also used.

Amortization: Amortization is a gradual reduction in the book value of an intangible asset, or of the amount contributed by City Light to a tangible asset owned by another entity (e.g., the Puget Intertie). The value of such assets is amortized over a certain time period and the associated expense is charged against income each year. The amortization expense related to various City Light assets is assigned to related functional categories for purposes of unbundling the revenue requirements. These include:

- Power – Deferred O&M costs related to mitigation of environmental impacts associated with the 1995 relicensing of City Light's Skagit River projects and fish habitat restoration at the Skagit and Tolt facilities in compliance with the federal Endangered Species Act. The contribution to the Skagit Environmental Endowment made by City Light under the terms of the High Ross Contract is also included.

  The High Ross contract refers to the 1984 agreement between City Light and the Canadian Province of British Columbia, whereby City Light agreed not to raise the height of Ross Dam on the Skagit River (which would have flooded Canadian land) and the Province agreed to provide energy to City Light in exchange for payments approximating the cost of the proposed addition to the dam. In 2000, City Light began deferring $9.1 million of the annual $21.8 million payments over the period through 2035. At the same time, City Light began amortizing a portion of the costs associated with the High Ross contract.

The forecast of deferred O&M costs for the 2013-2014 rate case also included environmental mitigation related to the 2013 relicensing of Boundary Dam. In 2013, City Light accountants reclassified Boundary relicensing environmental mitigation as a CIP project; therefore, the forecast of deferred O&M no longer includes these costs.

- Conservation – Costs of installed conservation measures are amortized over 20 years. Examples include installations under the Home Energy Loan Program, the Low-Income Electric Program, the Multifamily Conservation Program, the Smart Business Program, the Energy Smart Design Program and the Residential Efficient Lighting Program. The costs are partially offset by conservation credits from BPA.

- Long-Distance Transmission – Amortization associated with the Puget Stillwater Substation, which is used to transmit South Fork of the Tolt output via Puget Sound Energy facilities to City Light's service area.

Contributions in Aid of Construction (CIAC) and Grants: CIAC includes payments from customers for electrical service installation charges, non-standard service (e.g., underground service or a second feeder), feeder relocation or replacements, and other contributions. Grants are payments from government agencies to cover costs of a requested project. Nearly all forecasted contributions in 2015 and 2016 relate to transmission and distribution projects, though a minor amount is also attributable to generation projects. CIAC is allocated to functionalized categories based on the proportion of 2012 depreciation in each functional category to which CIAC usually applies, which include in service area transmission and all distribution categories except meters. Depreciation is used as the allocator because contributions are capitalized.

Interest: This expense category includes interest accrued on debt and amortization of debt expenses, with an offset from interest earnings. Interest was allocated to all functional categories of expense based on the book value of plant and other deferred debits in those categories as of the end of 2012. Book values include shares of general plant in all functional categories, computed as described under depreciation, as well as the assignment of the book value of deferred debits to a related function. The latter include assignment of: unamortized hydro project relicensing, High Ross and Skagit endowment to production and purchased power (power), unamortized programmatic conservation measures to conservation, and unamortized Puget Stillwater Substation expenses to long-distance transmission. The book values on which interest allocations are based are shown in **Table 2.4**.

Table 2.4: Book Values of Plant and Deferred Debits

	2012	Percentage
Power	$624,741,537	27.1%
Hydroelectric Plant	389,701,536	
Share of General Plant	31,277,598	
Unamortized Hydro Project Relicensing	83,303,345	
Unamortized High Ross	120,459,058	
Conservation	191,139,247	8.3%
Unamortized Conservation	190,543,331	
Share of General Plant	595,916	
Transmission		
Long-Distance Transmission	65,353,349	2.8%
Transmission Plant	60,494,086	
Share of General Plant	3,965,690	
Puget Intertie & Stillwater Substation	893,573	
In-Service-Area Transmission	83,838,374	3.6%
Transmission Plant	78,680,475	
Share of General Plant	5,157,899	
Distribution		
Stations	84,278,268	3.7%
Distribution Plant	79,799,601	
Share of General Plant	4,478,667	
Wires and Related Equipment	961,929,171	41.7%
Distribution Plant	910,810,891	
Share of General Plant	51,118,280	
Transformers	184,412,448	8.0%
Distribution Plant	174,612,509	
Share of General Plant	9,799,939	
Meters	51,477,622	2.2%
Distribution Plant	48,742,028	
Share of General Plant	2,735,594	
Streetlights/Floodlights	45,994,304	2.0%
Distribution Plant	43,550,102	
Share of General Plant	2,444,203	
Customer Accounts and Services	10,692,484	0.5%
Share of General Plant	10,692,484	
Utility Discount Program	228,217	0.0%
Share of General Plant	228,217	
Total	**$2,304,085,020**	**100.0%**

A&G Expenses: The basic A&G expense category includes administrative salaries, office supplies, outside services, property insurance, injuries and damages, employee pensions and benefits, rents, general plant maintenance and miscellaneous general expenses.

A&G expenses also include the amortization of deferred O&M expenses for environmental cleanup. Federal and State environmental regulations require this environmental remediation of the Lower Duwamish Waterway federal Superfund site, several areas located in proximity to the Duwamish Waterway, and a few other properties in diverse locations.

A&G from the financial model is adjusted by the addition of King County surface water management fees and by subtraction of miscellaneous income and Washington State Department of Ecology operating grants to fund toxic cleanup. These expenses are allocated by percentages of non-A&G labor hours in each functional category in 2012.

Revenue Taxes, County Payments and Franchise Payments: A public utility tax paid to the State of Washington (3.8734%), the City of Seattle's Occupation tax (6.0%), an Oregon tax on City Light's portion of the Third AC transmission intertie, and a small Renton business tax comprise the Department's tax expense. In order to allocate these amounts to all revenue requirement functions, the sum of all expenses except taxes in each category is multiplied by the effective tax rate.

Contract payments to suburban cities with which City Light has franchise agreements are not taxes, but are similarly applied to revenue totals.

In addition, payments are made to county governments for services provided in counties where City Light has generation facilities. Services include fire and police protection, schools, and road maintenance. Payments are made to Whatcom County and the Concrete School District for services associated with the Skagit projects, and to Pend Oreille County for services related to the Boundary project.

Net Income: City Light's net income is a residual after all revenues and expenses are taken into account. Net income contributes to the Utility's equity. The net income allocation procedure first assumes a 7% return on expected equity for the revenue requirement year, which corresponds generally to the City's Discount Rate Policy. Then, the percentages of book values shown in **Table 2.4** were used as a proxy for each unbundled component's share of equity and that percentage was multiplied times the 7% return amount. The remainder of net income is assigned to the power component as a risk management premium due to the weather-related variability of power supply. 2015 net income has been adjusted downward by $23 million to reflect the removal of $18 million of gains on surplus property sales and the shifting of $5 million CIAC from 2015 to 2016. Net income for 2016 has been adjusted upward by $5 million to reflect the $5 million in CIAC shifted from 2015.

2.4. Non-network and Network Expenses

Two distribution sub-functions (wires and related equipment, and transformers), are further split into non-network and network components. The network cost components shown below include all City Light's network areas (downtown, First Hill and University District). For cost allocation purposes, approximately 85% of the network costs shown below are allocated to the downtown network; this allocation is based on historical consumption percentages. The other 15% of the network costs shown is reallocated back to non-network classes because, at the present time, First Hill and University District network customers are treated as non-network customers for rate-making purposes.

The division of the O&M expenses into non-network and network components is based on an analysis of historical 2011 and 2012 distribution expenses recorded in FERC accounts. This process of distributing historical expenses between non-network and network components uses direct assignment where the FERC account value clearly applies to one component (e.g., maintenance of underground network equipment or maintenance of network underground line transformers and devices is assigned to the network component); and 2011 and 2012 labor hours to allocate the expense where it applies to both components (e.g., supervision, load dispatching, safety programs).

The 2015 and 2016 percentages used to allocate O&M expenses for wires and related equipment and transformers between network and non-network differ slightly because streetlight O&M expenses and labor hours allocated to these other distribution sub-categories differ.

The 2015 and 2016 non-network/network breakdown of projected revenue requirements for wires and related equipment and transformers is shown in **Table 2.5**.

Table 2.5: 2015 and 2016 Non-network/Network Expenses

	2015		**2016**	
Wires and Related Equipment	**Non-network**	**Network**	**Non-network**	**Network**
Wires and Related Equipment	$32,517,160	$3,329,735	$33,216,724	$3,400,040
Property Rental Income	(2,341,574)	(239,776)	(2,397,989)	(245,457)
Revenue from Damage	(1,071,662)	(109,737)	(1,097,481)	(112,337)
Other O&M Revenue	(7,521,766)	(770,224)	(7,981,678)	(816,999)
Construction (Installation) Charge Revenue	(907)	(93)	(907)	(93)
Pole Attachment Revenue	(2,674,867)	0	(2,674,867)	0
Distribution Capacity Charge	(223,343)	0	0	0
Power Factor Revenue	(2,676,712)	(274,094)	(2,741,830)	(280,652)
Subtotal	$16,006,328	$1,935,812	$16,321,972	$1,944,503
Plant Depreciation	35,977,615	20,125,243	37,066,950	20,734,598
Contributions and Grant Revenues	(19,383,857)	(10,842,988)	(25,191,170)	(14,091,496)
Interest	22,296,219	12,472,111	24,923,653	13,941,852
Administrative and General	13,407,897	937,755	13,943,762	976,195
Taxes	9,006,688	3,247,474	9,065,794	3,179,161
Net Income	26,335,295	14,731,499	28,788,014	16,103,507
Total Wires and Related Equipment	$103,646,184	$42,606,907	$104,918,976	$42,788,320
	2015		**2016**	
Transformers	**Non-network**	**Network**	**Non-network**	**Network**
Transformers	$566,162	$3,073,903	$579,596	$3,133,584
Credits for Customer-Owned Transformers	375,941	0	384,251	0
Subtotal	$942,103	$3,073,903	$963,847	$3,133,584
Plant Depreciation	6,337,270	4,399,517	6,529,151	4,532,726
Contributions and Grant Revenues	(3,414,366)	(2,370,352)	(4,437,294)	(3,080,498)
Interest	3,934,222	2,731,251	4,397,839	3,053,108
Administrative and General	94,981	1,602,867	98,814	1,667,653
Taxes	1,040,941	1,244,400	1,020,254	1,257,232
Net Income	4,646,927	3,226,031	5,079,715	3,526,485
Total Transformers	$13,582,078	$13,907,617	$13,652,326	$14,090,290

2.4.1. Wires and Related Equipment

For the wires and related equipment sub-function, pole attachment revenue and reserved distribution capacity revenue are assigned to the non-network category, and the remaining expenses (including adjustments) are multiplied by the percentage of 2011 and 2012 expenses calculated for each category (90.71% non-network and 9.29% network). Plant depreciation, contributions and grants, interest expense and net income are distributed between non-network and network components based on a "capital" allocator. This allocator is developed using the 1993-2012 capital additions for FERC accounts 364-367 (Poles, Towers and Fixtures; Overhead Conductors and Devices; Underground Conduit; Underground Conductors and Devices) from depreciation schedules. Additions in FERC 36664 (Underground Conduit-Network) and FERC 36764 (Network UG Conductors and Devices) are assigned to the network component, while the other FERC sub-accounts are assigned to the non-network component. Amounts in each category are summed and the resulting percentages of the total are used as the non-network/network "capital" allocator (64.13% non-network and 35.87% network).

A&G expense is allocated by 2012 labor hours in the non-network and network sub-categories of the wires and related equipment sub-function (93.46% non-network and 6.54% network). Taxes are computed for the non-network and network expense components by multiplying the expenses calculated in the processes described above by the effective tax rate of 14.66%. Net income is allocated between non-network and network components based on the share each has of additions to wires-related capital investments, averaged over the past 20 years to avoid biases associated with short term investment decisions.

2.4.2. Transformers

Projected O&M expenses are multiplied by the percentage of 2011 and 2012 expenses in each category (15.55% non-network and 84.45% network in 2015, 15.61% non-network and 84.39% network in 2016). The additional expense of Credits for Customer-Owned Transformers is assigned only to the non-network component because customers who receive this credit are located outside the network.

Plant depreciation, contributions and grants, interest and net income are distributed between non-network and network components based on a "capital" allocator. This allocator is based on an analysis of the 1993-2012 capital additions for FERC account 368 (Line Transformers) from depreciation schedules. Additions to FERC 36864 (Network UG Transformers-Installed Cost) are assigned to the network component, while the other FERC sub-accounts are assigned to the non-network component. Amounts in each category are summed and the resulting percentages of the total are used as the non-network/network "capital" allocator (59.02% non-network and 40.98% network).

A&G expense is allocated by 2012 labor hours in the non-network and network sub-categories of the transformer category (5.59% non-network and 94.41% network). Taxes are computed for the non-network and network expense components by multiplying the expenses calculated in the processes described above by the effective tax rate. Net income related to transformers is allocated between non-network and network components based on the share each has of additions to transformer capital investments, averaged over the past 20 years to avoid biases associated with short term investment decisions.

3. Cost of Service and Allocation Factors

3.1. Marginal Cost Approach

City Light uses a marginal cost approach in estimating the cost of providing services to customers for purposes of allocating revenue requirements. Marginal costs measure how a utility's cost picture changes when cost of inputs changes, load is changed and/or the number of customers in the system changes. Only current (or near term future) costs are included in the marginal cost estimates. Average costs, by contrast, are derived by dividing a utility's total costs by total load, maximum demand, or the number of customers. A marginal cost approach was used in the last 11 City Light complete rate cases that included cost allocations (1980, 1982, 1984, 1986, 1989-1990, 1993, 1995-1996, 1997-1998, 1999, 2007-2008 and 2013-2014).

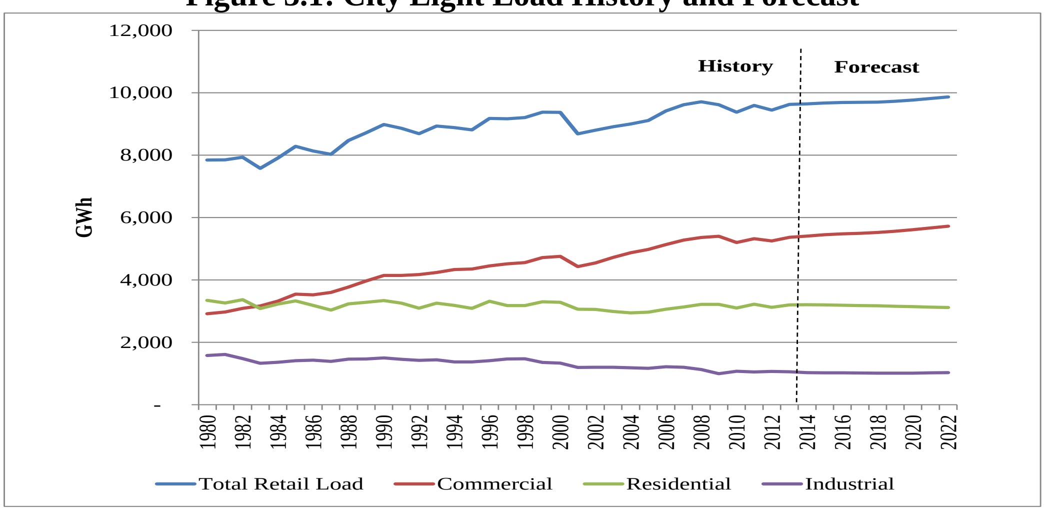
3.2. Load Overview

The retail load forecast is the single most important input for determining the total cost of energy and for allocating the total energy cost to individual customer classes and service areas. In addition, load data is used to allocate certain distribution costs.

3.2.1. History and Forecast

City Light's retail load forecast is based on forecasts of selected economic and demographic variables for the service territory and includes assumptions about City Light sponsored conservation programs and customer price elasticity of demand. **Figure 3.1** shows the retail load forecast, which was produced in the spring of 2013. The forecast projects low load growth for the commercial sector and flat to declining growth for the residential and industrial sectors.

Figure 3.1: City Light Load History and Forecast



To develop billing determinants, the commercial and industrial load is allocated into Small, Medium, Large and High Demand customer classes. Load is further divided into network and non-network classes. **Tables 3.1** and **3.2** show forecasted consumption by customer class for 2015 and 2016, respectively. Of particular note, the forecast of streetlight load ("Lights") is declining because of LED conversion.

Table 3.1: Energy Consumption by Customer Class in 2015

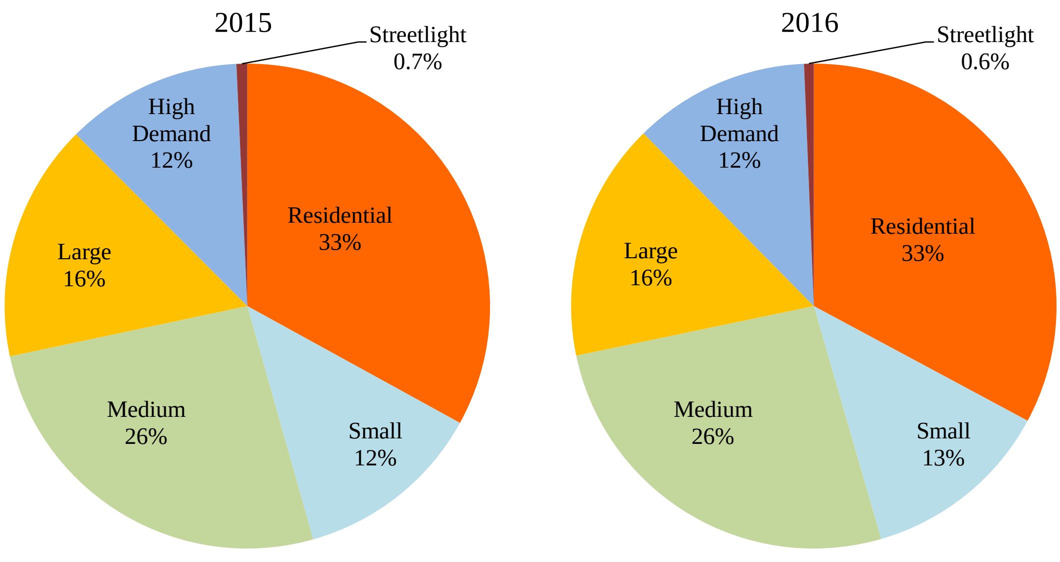
2015	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,567,320	3,157,663	1,207,275	2,492,299	1,517,275	1,124,315	68,493
Non-network	8,156,323	3,064,864	1,062,355	1,916,508	919,789	1,124,315	68,493
Network	1,410,997	92,799	144,921	575,791	597,486		

Table 3.2: Energy Consumption by Customer Class in 2016

2016	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	9,611,431	3,156,805	1,218,984	2,517,689	1,528,115	1,127,827	62,011
Non-network	8,190,141	3,064,069	1,072,909	1,937,438	925,887	1,127,827	62,011
Network	1,421,289	92,736	146,075	580,250	602,227		

Figure 3.2 presents the consumption mix by customer class. Residential electricity consumption constitutes 33% of total retail load whereas non-residential is 67%. There are no major differences in the consumption mix between the two years.

Figure 3.2: Percent of Retail Sales by Customer Class, 2015-2016



The monthly retail forecast is developed using historical consumption patterns. **Figures 3.3** and **3.4** show the monthly forecast of electricity consumption by customer class in 2015 and 2016 by peak and off-peak periods. The peak period is defined as Monday–Saturday 6 a.m. to 10 p.m.

and the off-peak period is 10 pm to 6 am Monday-Saturday, all day Sunday and NERC (North American Electric Reliability Corporation) holidays. Note that only residential customers have a clear seasonal pattern to their consumption, driven by heating and lighting loads.

Figure 3.3: Peak Retail Sales by Customer Class, 2015-2016

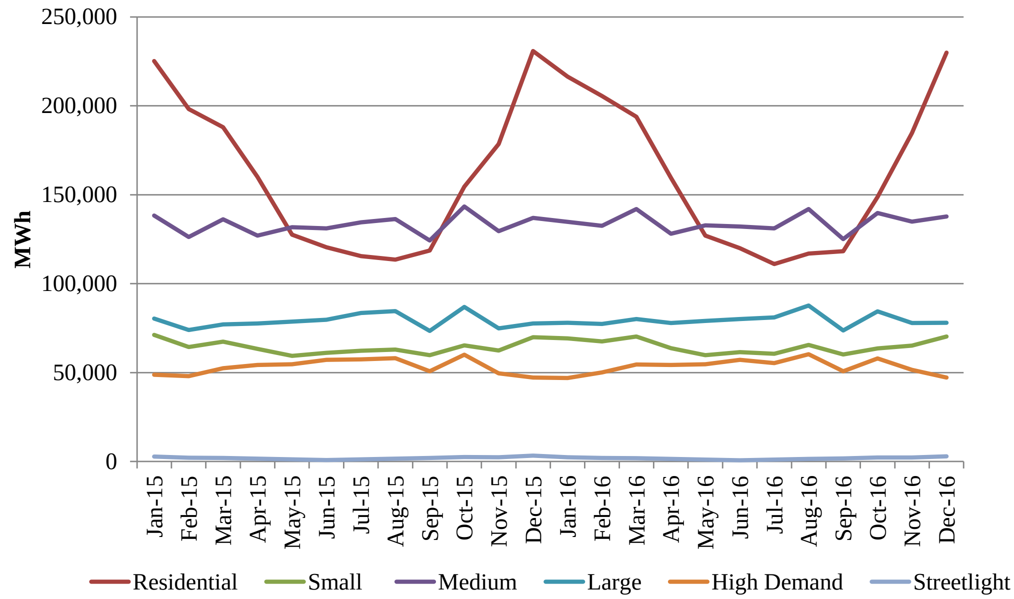
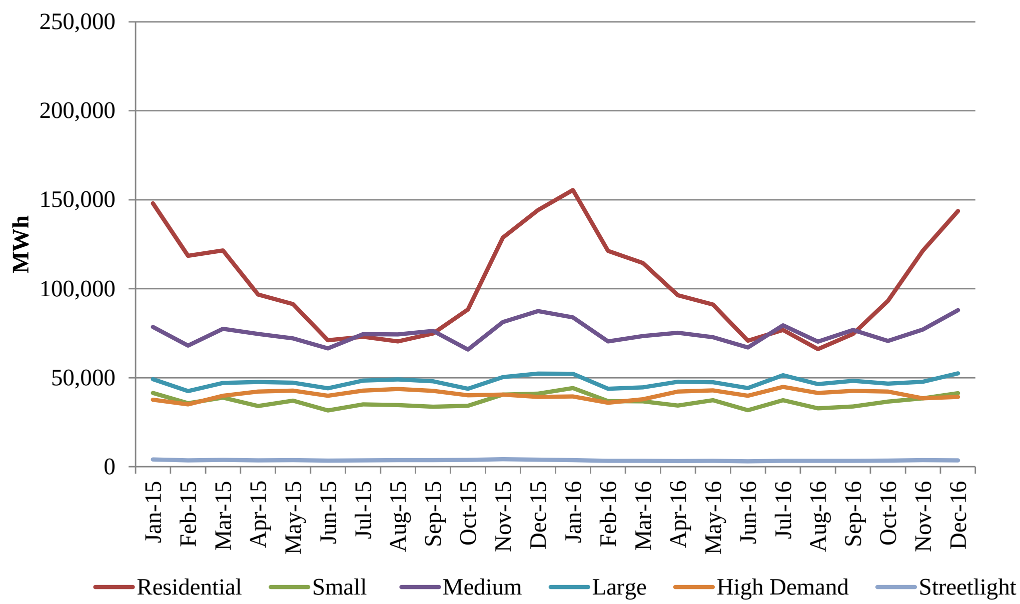


Figure 3.4: Off-Peak Retail Sales by Customer Class, 2015-2016



3.2.2. Peak Load Data

Coincident peak load is used to estimate certain distribution costs. Peak load is defined as the maximum of either peak or off-peak monthly average consumption. This peak load for the total system is also the coincident peak load. For customer classes the coincident peak load is the average monthly load during the month of the total system coincident peak. **Table 3.3** summarizes average and coincident peak load for 2015 and 2016 by customer class. City Light's system peak occurs in the January peak period.

Table 3.3: Annual Average and Coincident Peak Load

Non-network (Excludes Network Residential & Small that are billed at non-network rates)								
		Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Average Annual Load, MW	2015	931.1	349.9	121.3	218.8	105.0	128.3	7.8
	2016	932.4	348.8	122.1	220.6	105.4	128.4	7.1
Load at Coincident Peak*, MW	2015	1,171.7	525.5	150.6	257.0	115.0	117.1	6.6
	2016	1,177.2	525.2	152.4	260.6	115.9	117.2	5.9
Network								
		Total	**Residential**	**Small**	**Medium**	**Large**		
Average Annual Load, MW	2015	161.1	10.6	16.5	65.7	68.2		
	2016	161.8	10.6	16.6	66.1	68.6		
Load at Coincident Peak*, MW	2015	190.1	13.8	19.8	77.1	79.3		
	2016	191.9	15.9	20.8	76.2	79.0		

*Coincident peak occurs during January Peak hours.

3.2.3. System Losses

Energy losses are a natural byproduct of transmission and distribution; therefore, the total amount of energy generated or purchased to meet load is greater than just system load. For the purposes of marginal cost analysis, these losses are estimated as a percentage of load. **Table 3.4** shows system losses for the periods of maximum loads at different points of energy flowing through the system.

Network losses are calculated separately because losses created in a network are less than in a non-network for transformers and feeders due to (*N-1)* design loading. There is no distinction in losses between network and non-network customers, though, from the service territory boundary to the low side of a substation's transformer, nor in the service drop from a customer's transformer to the customer. In the case of network service for Medium and Large General Service customers, maximum losses for feeders and customer transformers equal 4/9 times the losses in **Table 3.4**.

Table 3.4: System Losses for Periods of Maximum Loads (% of Load)[1]

Energy Flow Point	Residential	Small and Streetlights	Medium	Large and High Demand
Long distance transmission from generation point to service area boundary	1.90%	1.90%	1.90%	1.90%
In service area transmission from service area boundary to substation	1.14%	1.14%	1.14%	1.14%
Through substation	0.74%	0.74%	0.74%	0.74%
Through 26/13 kV feeders to the high side of the customer transformers	0.82%	0.82%	0.82%	0.82%
Customer transformers and service drop	1.77%	2.31%	0.98%	0.89%

Tables 3.5 and **3.6** present an annual summary of all the losses, which were derived by using projections of load in terms of average MW per hour by two costing periods for each month and the calculations mentioned above. **Tables 3.7** and **3.8** present the annual summary of total energy (energy consumption plus losses) required to serve each customer class.

Table 3.5: 2015 Energy Losses by Customer Class

2015	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	447,762	142,195	65,497	114,752	67,827	53,918	3,574
Non-network	386,185	138,211	58,031	89,698	42,753	53,918	3,574
Network	61,578	3,984	7,465	25,054	25,074		

Table 3.6: 2016 Energy Losses by Customer Class

2016	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	449,852	142,076	65,738	116,357	68,465	54,050	3,166
Non-network	387,705	138,098	58,259	91,009	43,122	54,050	3,166
Network	62,147	3,978	7,478	25,348	25,343		

[1] The energy and demand loss figures apply to the various components of the transmission and distribution system based on a fully converted 26 kV distribution system.

Table 3.7: 2015 Energy Consumption plus Losses by Customer Class

2015	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	10,015,082	3,299,858	1,272,772	2,607,050	1,585,102	1,178,233	72,068
Non-network	8,542,508	3,203,075	1,120,386	2,006,205	962,542	1,178,233	72,068
Network	1,472,574	96,783	152,386	600,845	622,560		

Table 3.8: 2016 Energy Consumption plus Losses by Customer Class

2016	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	10,061,283	3,298,882	1,284,722	2,634,045	1,596,580	1,181,877	65,178
Non-network	8,577,846	3,202,167	1,131,168	2,028,447	969,009	1,181,877	65,178
Network	1,483,437	96,714	153,554	605,598	627,570		

3.2.4. Meter Counts

Tables 3.9 and **3.10** show the projected average number of meters by customer class for 2015 and 2016, respectively. Since new customers (meters) are continuously getting added to the system while existing customers (meters) are continuously leaving the system, the meter count below is an estimate of the average number of meters for the class during the course of the year. The meter data is based on 2013 billing data, and since there is little change projected in system load, the counts remain constant for both years.

Table 3.9: 2015 Meter Count

2015	Total	Residential	Small	Medium	Large	High Demand
Service Territory	420,024	373,345	43,400	3,113	154	12
Non-network	399,730	356,895	40,156	2,572	95	12
Network	20,294	16,450	3,244	541	59	

Table 3.10: 2016 Meter Count

2016	Total	Residential	Small	Medium	Large	High Demand
Service Territory	420,024	373,345	43,400	3,113	154	12
Non-network	399,730	356,895	40,156	2,572	95	12
Network	20,294	16,450	3,244	541	59	

3.3. Energy Costs

Marginal energy costs are based on the assumption that City Light meets incremental load by purchasing power in the wholesale market and delivering it to its service territory using BPA transmission. The total energy cost for non-network and network is calculated using the formula below:

$$\sum_{i=1}^{12}(Q_{Pi}+L_{Pi})*(P_{Pi}+EA)+\sum_{i=1}^{12}(Q_{OPi}+L_{OPi})*(P_{OPi}+EA)+Long\ Distance\ Transmission\ Costs$$

where:

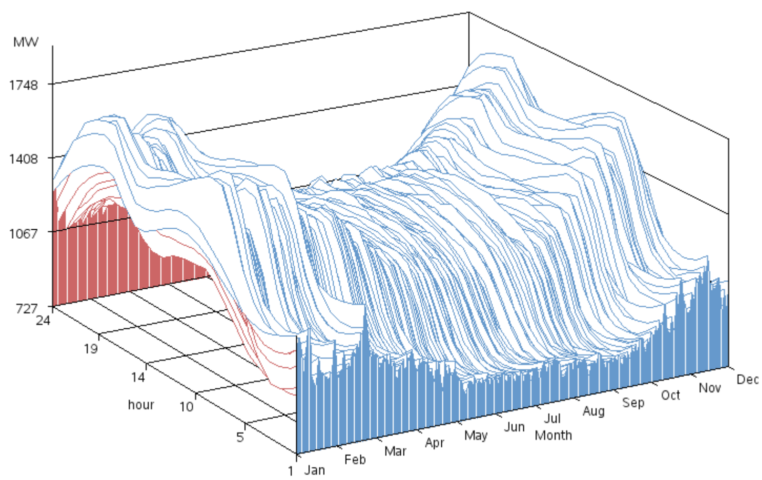
i=1 to 12 and represents a month; P is peak period; OP is off-peak period; Q is energy consumption; L is energy losses; P is wholesale market price; EA is externality adder.

3.3.1. Wholesale Market Electricity Prices

City Light buys and sells power primarily at the Mid-Columbia Trading Hub (Mid-C). Market prices are determined by supply and demand. Supply conditions of many hydroelectric plants in the Mid-C region are dictated to a great extent by rainfall and snow accumulation. Also affecting supply are the many rules and regulations imposed on the operation of hydro plants to protect against flooding and to provide for irrigation, boating and support of fish and wildlife.

The demand is influenced by temperature, time of the day, and day of the week. For example: in cold weather electric heating demand increases, and electricity demand is lower at night when people are asleep and businesses are closed. Also, weekend demand tends to be lower because many businesses close or curtail their operations. **Figure 3.5** shows the variation in electricity consumption by month and hour for a typical City Light year. This consumption pattern is similar across the Pacific Northwest.

Figure 3.5: Seasonality of City Light Electricity Demand in a Typical Year



Electricity prices in the Pacific Northwest tend to increase during winter months due to heating demand, then decrease in the spring during the hydro runoff season when there is an abundance of generation, and then pick up again in the summer as the runoff ends. Off-peak prices are generally lower than peak prices.

Figure 3.6 shows Dow-Jones Mid-C average monthly electricity prices for the period 2006-2013. Market prices were rising between 2006 and mid-2008, falling rapidly after that following the financial crisis in the fall of 2008, falling a little further in 2009-2012 due to lower natural gas prices, then gradually climbing upward from mid-2012 onward, attaining levels not seen since 2009 by the end of 2013. Note the price dip in the spring of each year, which coincides with the spring hydro runoff season.

Figure 3.6: Average Monthly Mid-C Electricity Prices, 2006-2013

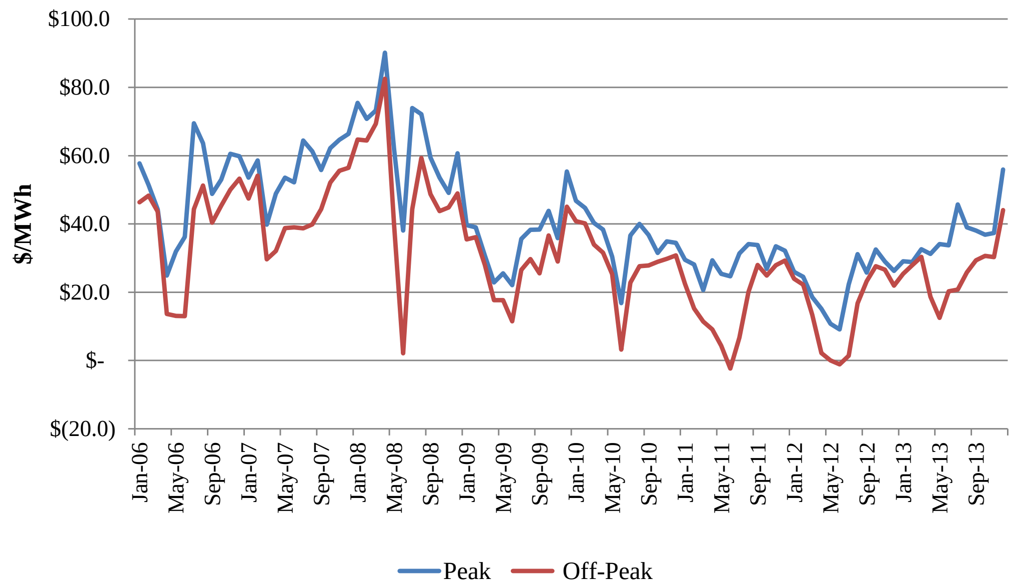
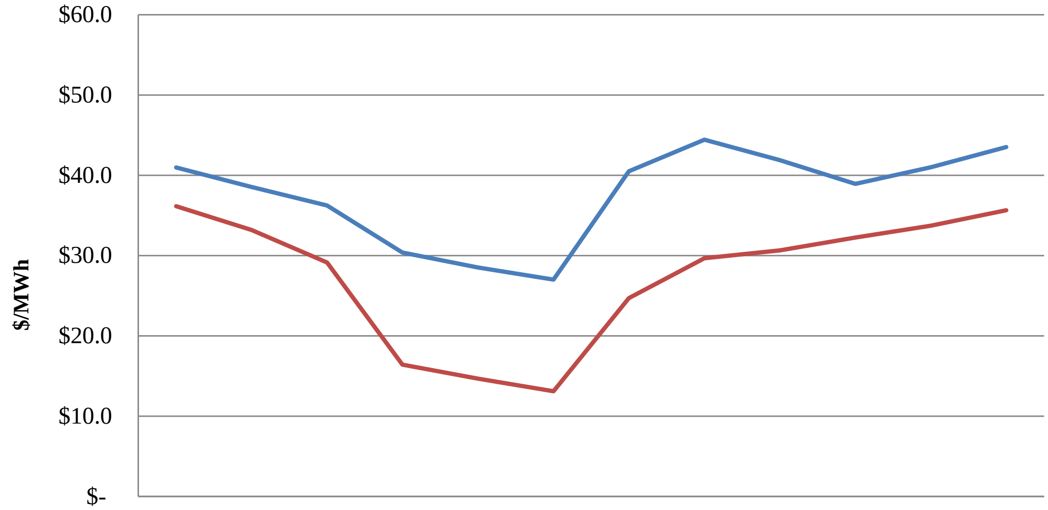
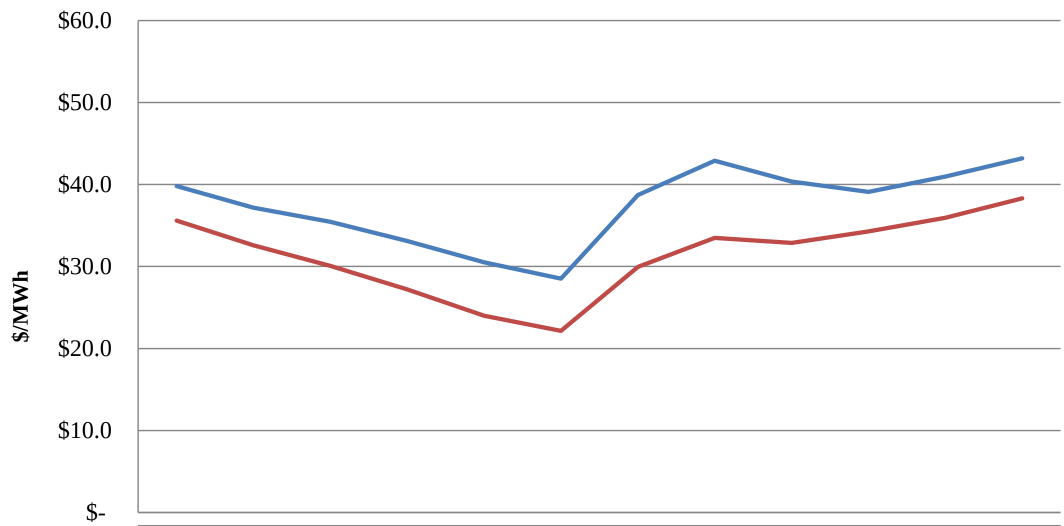


Figure 3.7 presents the forecast of monthly Mid-C electricity prices for 2015 and 2016 as of January 10, 2014. The 2015 forecast is based purely on forward wholesale energy prices, whereas the forecast for 2016 is based on a blend of forward prices and more long-term West Coast electricity market fundamentals. Peak prices are expected to remain around the same level in 2015 and 2016, but off-peak prices are expected to be slightly higher in 2016 than in 2015.

Figure 3.7: Monthly Mid-C Electricity Prices, 2015-2016



	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Peak	$41.0	$38.5	$36.2	$30.4	$28.5	$27.0	$40.5	$44.4	$41.9	$38.9	$41.0	$43.5
Off-Peak	$36.2	$33.2	$29.1	$16.4	$14.7	$13.1	$24.7	$29.7	$30.6	$32.2	$33.7	$35.7



	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Peak	$39.8	$37.2	$35.5	$33.1	$30.5	$28.5	$38.7	$42.9	$40.3	$39.1	$41.0	$43.2
Off-Peak	$35.6	$32.6	$30.1	$27.2	$24.0	$22.2	$30.0	$33.5	$32.9	$34.3	$35.9	$38.3

3.3.2. Negative Externalities

A byproduct of the production and delivery of electricity are negative consequences such as air, water, and soil pollution, respiratory health problems, reduced visibility, damage to fish and wildlife, and global warming. These externalities impose costs on the environment and society. Therefore, a true cost of electricity includes an estimate of these societal and environmental costs, which we refer to as “environmental externality adders.”

The environmental externality adder assumes that carbon dioxide (CO_2) emissions are the primary driver of externality impacts, so the adder is determined by multiplying the amount of CO_2 emitted per MWh by the cost to the environment per unit of CO_2 emitted. The amount of CO_2 emitted in electricity production on the margin was estimated by determining emission factors for the years 2012 and 2030 and then performing a straight line interpolation for the intervening years.

The 2012 emission factor is 0.583 metric tons of CO_2 per MWh, which was published by the Environmental Protection Agency (EPA) in 2011 for the Northwest Power Pool (NWPP) region of the Western Electric Coordinating Council (WECC) and was calculated from 2007 actual plant emissions. The 2030 emission factor is estimated at 0.389 metric tons of CO_2 per MWh; this is the emission rate of a new natural gas combined-cycle combustion turbine, which most closely approximates a marginal resource in the Pacific Northwest.

The price of CO_2 emissions for the period 2012–2017 is based on the City Light forecast of the cost of greenhouse gas offsets for those years. Starting in 2018, the price of CO_2 emissions is based on a Synapse (a consulting firm) study of the federal Waxman-Markey and American Power Act proposals as of 2010. These prices are assumed to be applied to all CO_2 emissions.

The environmental externality adder is calculated by multiplying the amount of CO_2 emitted per MWh by the price of CO_2 emissions. **Table 3.11** shows emission factors, price of CO_2 emissions and resulting adders for 2015 and 2016.

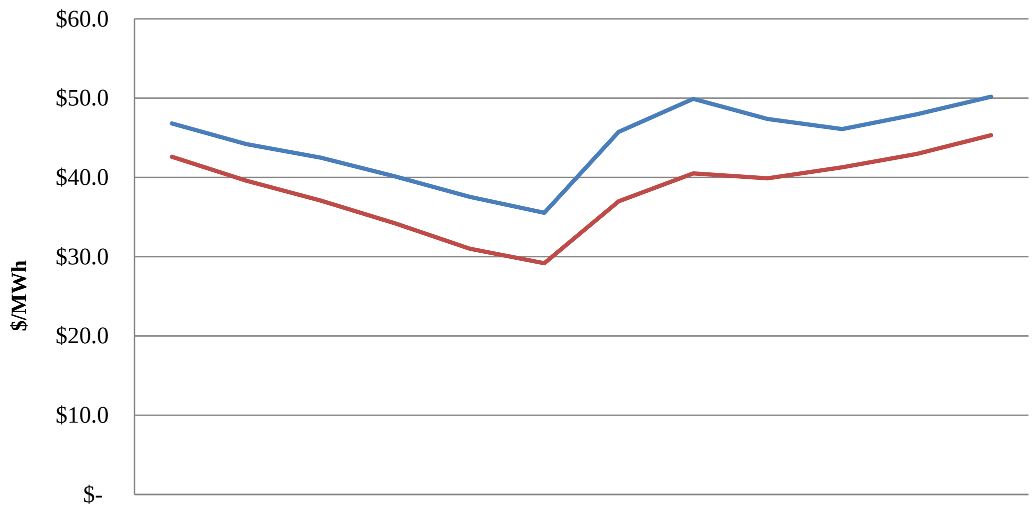
Table 3.11: Environmental Externality Adders, 2015-2016

Year	CO_2 Emission Factor (metric tons/MWh)	Price of CO_2 Emissions ($/metric ton, in 2012$)	Environmental Externality Adder ($/MWh, in 2012$)
2015	0.551	$11.00	**$6.06**
2016	0.540	$12.00	**$6.48**

Figure 3.8 presents the forecast of Mid-C monthly electricity prices plus externality costs for 2015 and 2016.

Figure 3.8: Monthly Mid-C Electricity Prices plus Externality Costs, 2015-2016

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Peak	$47.4	$44.9	$42.7	$36.8	$34.9	$33.4	$46.9	$50.8	$48.3	$45.4	$47.4	$49.9
Off-Peak	$42.6	$39.6	$35.5	$22.8	$21.1	$19.5	$31.1	$36.1	$37.1	$38.6	$40.1	$42.1



	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Peak	$46.8	$44.2	$42.5	$40.1	$37.5	$35.5	$45.7	$49.9	$47.4	$46.1	$48.0	$50.2
Off-Peak	$42.6	$39.6	$37.1	$34.2	$31.0	$29.2	$37.0	$40.5	$39.9	$41.3	$43.0	$45.3

3.3.3. Energy Consumption plus Losses Costs

Tables 3.12 and **3.13** present total costs of energy consumption plus losses by customer class for 2015 and 2016. These costs were calculated for each customer class in non-network and network categories by multiplying total monthly peak and off-peak load plus losses by the associated projected monthly market price plus externality adder, and then summing results for each year. Note that the costs increase in 2016 for all customer classes except lights, reflecting the expected slight increase in off-peak wholesale electricity prices and the projected increase in the externality costs. The dip in costs for lights reflects the lower consumption that year for lights.

Table 3.12: Energy Consumption plus Losses Costs in 2015

2015	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$405,670,768	$134,928,620	$51,734,357	$105,791,407	$63,940,997	$46,538,403	$2,736,983
Non-network	345,898,802	130,968,225	45,531,550	81,425,145	38,698,495	46,538,403	2,736,983
Network	59,771,966	3,960,395	6,202,807	24,366,262	25,242,502		

Table 3.13: Energy Consumption plus Losses Costs in 2016

2016	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$426,673,499	$140,746,548	54,569,935	$111,790,191	$67,525,104	$49,370,204	$2,671,518
Non-network	363,707,380	136,618,409	48,042,596	86,099,418	40,905,236	49,370,204	2,671,518
Network	62,966,119	4,128,139	6,527,339	25,690,773	26,619,868		

3.3.4. Long Distance Transmission Costs

All City Light energy generation occurs outside the service territory and requires long distance transmission to transmit power to end users. In practice, the Department purchases the bulk of its transmission via long-term contracts. However, for the purposes of marginal cost analysis, transmission costs are valued a single year at a time, with the amount purchased sized to serve the peak demand each the year.

The amount of transmission capacity needed is estimated by multiplying annual average load by 170%, a percentage derived from historical load data that approximates the relationship between average and peak system load. The annual average load (this can be found in **Table 3.3** by adding network and non-network totals) for the service territory is 1,092 MW for 2015 and 1,094 MW for 2016. Transmission capacity required therefore is 1,856 MW and 1,860 MW for 2015 and 2016 respectively.

The price for BPA transmission services is $1,736/MW per month in 2015 and $1,975/MW per month in 2016. The annual long distance transmission costs, therefore, are $40,003,564 for 2015 and $44,077,260 for 2016, which must be allocated among customer classes.

An estimate of the quantity of transmission services needed to serve each class on its own was developed as if it were the only class being served.[2] The results were summed over all classes. Shares of the cost of transmission from this set of calculations were then used to allocate the costs of transmission from the analysis of the actual system load. This process yields a fair apportionment of the net cost of transmission services while preserving a useful estimate of the marginal value of transmission services for each customer class. **Tables 3.14** and **3.15** present long distance transmission costs by customer class in 2015 and 2016.

[2] Following the procedure for calculating the amount of capacity for the total system, the amount of capacity that theoretically would be purchased for each class would be 170% of the average load for each class. Therefore, each class is allocated the same percentage of the total system transmission costs as its share of load.

Table 3.14: Long Distance Transmission Costs in 2015

2015	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$40,003,564	$13,203,047	$5,047,945	$10,420,977	$6,344,139	$4,701,066	$286,390
Non-network	34,103,803	12,815,028	4,441,993	8,013,439	3,845,887	4,701,066	286,390
Network	5,899,760	388,019	605,952	2,407,538	2,498,251		

Table 3.15: Long Distance Transmission Costs in 2016

2016	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$44,077,260	$14,476,859	$5,590,165	$11,545,921	$7,007,813	$5,172,123	$284,380
Non-network	37,559,340	14,051,579	4,920,274	8,884,939	4,246,045	5,172,123	284,380
Network	6,517,920	425,280	669,891	2,660,983	2,761,767		

City Light does earn a small amount of revenue seasonally from sales of surplus transmission capacity. However, in this analysis the long-distance transmission costs are allocated gross of this revenue.

3.3.5. Total Energy Costs

The total energy cost is the sum of energy consumption plus losses costs and costs of long distance transmission derived in sections 3.3.3 and 3.3.4, respectively. **Tables 3.16** and **3.17** show total energy costs by customer class for 2015 and 2016. These costs are used to derive energy allocation factors by customer class summarized in Section 3.6.

Table 3.16: Total Energy Costs in 2015

2015	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$445,674,331	$148,131,667	$56,782,302	$116,212,385	$70,285,136	$51,239,470	$3,023,373
Non-network	380,002,605	143,783,254	49,973,543	89,438,585	42,544,382	51,239,470	3,023,373
Network	65,671,726	4,348,414	6,808,759	26,773,800	27,740,754		

Table 3.17: Total Energy Costs in 2016

2016	Total	Residential	Small	Medium	Large	High Demand	Lights
Service Territory	$470,750,759	$155,223,407	$60,160,100	$123,336,112	$74,532,916	$54,542,327	$2,955,898
Non-network	401,266,720	150,669,987	52,962,870	94,984,356	45,151,281	54,542,327	2,955,898
Network	69,484,039	4,553,419	7,197,230	28,351,756	29,381,635		

3.4. Distribution Costs

In this section we derive total distribution costs by customer class for 2015 and 2016. Total distribution costs are composed of the marginal costs of:

1. In service area transmission costs;
2. Substation costs;
3. Wires and related equipment costs;
4. Customer transformer costs;
5. Meter (excluding meter reading) costs;
6. Streetlights costs (from Chapter 2, Table 2.2, Functionalized Revenue Requirements).

These costs cover purchase, maintenance and replacement of the equipment and facilities necessary to provide distribution service to existing and new customers. Costs by customer class are developed in three steps. First, estimates of annualized capital costs and annual operations and maintenance (O&M) costs per MW (per meter for meter costs) for the indicated component are developed. Second, these per unit costs are multiplied by the appropriate coincident peak load (or number of meters) for each class. Third, the sum of these costs is computed for each class.

In developing marginal costs of distribution equipment and services we use an estimate of how much it would cost to replace this equipment today, not how much it cost originally. These estimates are obtained from a combination of engineering estimates of recent and ongoing projects, FERC accounts, and current catalogue costs of specific equipment as well as standardized work practices.

3.4.1. In Service Area Transmission

In service area transmission costs consist of the O&M and capital costs associated with the delivery of energy through high voltage lines from the service territory boundary to substations.

In Service Area Transmission Capital Costs

City Light's in service area high-voltage transmission lines have a peak capacity of 2,892 MW. **Table 3.18** presents the capital cost required to replace all in service area transmission lines. Per-mile cost estimates are developed by City Light engineers using costs of recent actual replacements of major in service area transmission lines. There were no major changes from the previous cost of service study; dollar values have only been updated to reflect inflation. These costs are multiplied by estimates of miles of line within the service territory. Appendix A indicates that the expected service life for this type of equipment is 45 years with a corresponding annualization factor of 0.040187. The total equipment cost is multiplied by the annualization factor, and divided by total in service area capacity to obtain the capital cost per MW.

The capacity must cover 2.7% losses on the system, which are to be the sum of assumed transmission losses through the service territory (1.14%), substations (0.74%) and feeders (0.82%), as shown in **Table 3.4**. The cost per MW is adjusted for losses by dividing through by (1-loss factor) as shown in **Table 3.18**.

Table 3.18: In Service Area Transmission Capital Costs

	Miles	2012 $Millions/Mile	Total 2012$Millions
115 kV			
OH	97.2	$3.1	$299.1
UG	21.1	10.3	216.4
Subtotal	118.3	4.4	515.5
230 kV			
OH	92.9	$3.6	$333.3
UG	19.2	12.3	235.6
Subtotal	112.0	5.1	569.0
Total	**230.4**	**$4.7**	**$1,084.4**
Annualization factor			0.04019
In Service Area Capacity (MW)			2,892
Loss Factor			2.7%
Annual Capital Cost $2012 /per MW			**$15,487**

In Service Area Transmission O&M Costs

In service area transmission O&M costs are based on a three-year average of actual costs, adjusted for inflation. **Table 3.19** presents the costs associated with in service area transmission by FERC account for 2010 through 2012. Dividing by in service area capacity produces annual O&M cost per MW.

Table 3.19: In Service Area Transmission O&M Costs for 2010-2012

FERC Code	FERC #	2010	2011	2012
OS&E-INSIDE SEATTLE	56016	$30,012	$12,234	$17,062
O-STATION EXP, INSIDE SEATTLE	56216	103,698	78,001	27,008
OP OV LINE EXP-INSIDE SEATTLE	56316	14,107	2,444	0
OP UN LINE EXP-INSIDE SEATTLE	56416	30,995	5,727	4,064
OP MISC L EXP-INSIDE SEATTLE	56616	56,959	8,517	0
MS&E-INSIDE SEATTLE	56816	97,826	45,015	36,614
MAINT TRANS ST-INSIDE SEATTLE	56916	111,805	92,279	82,792
MAINT RELAY SE-INSIDE SEATTLE	57016	163,062	95,641	127,045
MAINT STAT EQ-INSIDE SEATTLE	57026	432,256	615,035	468,686
ROADS & TRAILS-INSIDE SEATTLE	57116	117,128	168,328	133,013
TOWERS & POLES-INSIDE SEATTLE	57126	6,241	28,567	0
M O/H TRANS CO-INSIDE SEATTLE	57136	14,443	12,503	(9,102)
CLR TREE&BRSH-INSIDE SEATTLE	57146	272,121	393,276	24,780
MAINT O/H ENG-INSIDE SEATTLE	57156	0	141	380
U/G NON ELEC EQ-INSIDE SEATTLE	57216	0	0	1,385
U/G ELEC EQ-INSIDE SEATTLE	57226	9,631	3,638	0
U/G ELEC ACCESS-INSIDE SEATTLE	57236	0	367	0
U/G MAINT ENG-INSIDE SEATTLE	57246	0	0	0
MISC TRANS PLA-INSIDE SEATTLE	57316	2,343	3,091	65,102
Subtotal (excludes 56016 - a supervisory cost)		1,432,614	1,552,572	961,765
Subtotal in $2012		**$1,515,569**	**$1,591,996**	**$961,765**
Three Year Average				$1,356,443
In Service Area Capacity (MW)				2,892
Annual O&M, $2012/MW				**$469**

Total In Service Area Transmission Costs by Customer Class

Tables 3.20 and **3.21** present total in service area transmission costs for 2015 and 2016, respectively. The costs are calculated using the following formula:

$$\frac{(Capital\ Costs/MW + O\&M\ Costs/MW) * Inflation * Class\ Coincident\ Peak\ Load * ISA\ Capacity}{Total\ Service\ Territory\ Peak\ Load}$$

Note that the $/MW are based on a cost per unit of total capacity that exceeds the load placed on the in service area transmission. Thus, to reflect costs for actual in service area transmission usage by a class, the $/MW cost of total capacity is multiplied by the class coincident peak load and that result is multiplied by the total in service area transmission capacity divided by the system peak load.

Table 3.20: 2015 In Service Area Transmission Costs

Capital Costs $2012/MW		$15,487					
O&M Costs $2012/MW		$469					
In Service Area Transmission Capacity MW		2,892					
2015 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,171.7	525.5	150.6	257.0	115.0	117.1	6.6
Network	190.1	13.8	19.8	77.1	79.3		
Service Territory	1,361.8						
2015 In Service Area Transmission Costs				**$2015 inflation adjustment =**			**1.05786**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$42,001,641	$18,837,444	$5,396,985	$9,212,487	$4,120,852	$4,198,001	$235,872
Network	$6,813,659	$494,598	$711,204	$2,765,158	$2,842,698		
Service Territory	$48,815,299	$19,332,042	$6,108,189	$11,977,645	$6,963,551	$4,198,001	$235,872

Table 3.21: 2016 In Service Area Transmission Costs

Capital Costs $2012/MW		$15,487					
O&M Costs $2012/MW		$469					
In Service Area Transmission Capacity MW		2,892					
2016 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,171.7	525.5	150.6	257.0	115.0	117.1	6.6
Network	190.1	13.8	19.8	77.1	79.3		
Service Territory	1,361.8						
2015 In Service Area Transmission Costs				**$2015 inflation adjustment =**			**1.05786**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$42,997,577	$19,183,061	$5,565,979	$9,519,070	$4,232,379	$4,280,488	$216,601
Network	$7,010,917	$580,915	$760,737	$2,782,074	$2,887,190		
Service Territory	$50,008,494	$19,763,976	$6,326,716	$12,301,144	$7,119,569	$4,280,488	$216,601

3.4.2. Substations

Substations transform high voltage power delivered by in service area transmission lines to lower voltages for distribution feeder lines. Whereas there are no differences among in service area transmission costs per MW for customer classes inside and outside the network, there are some differences in the capital costs of substations for non-network and network customers.

Substation Capital Costs

The Department is currently building a new 180 MW substation in the Denny Triangle area. This substation will support both 26 kV non-network feeders and 13 kV network feeders. Engineering estimates and costs developed for this project are the source of the initial capital cost estimates for network and non-network substations. **Table 3.22** presents total costs of replacement for a substation and associated annual capital costs per MW.

Table 3.22: Substation Capital Costs

	Network	Non-network
Total Costs of Replacement, $2012	**$34,708,513**	**$32,387,607**
Capacity (MW)	180	180
Annualization Factor	0.04833	0.04833
Loss Factor	1.56%	1.56%
Annual Capital Costs $2012/ MW	**$9,466**	**$8,833**

To derive the annual capital costs per MW, we first divided the total capital cost by the substation capacity, then multiplied it by the annualization factor, and lastly divided the annualized capital cost per MW by (1-loss factor).

Substation O&M Costs

Table 3.23 presents data on the annual O&M costs associated with the system's substations by FERC account, using a three year average adjusted for inflation. Substation operations and maintenance costs are adjusted for the age of facilities using an adjustment factor of 0.673, the derivation of which is described next.

Since reported O&M expenses cover all substations of all ages there is a concern that the average cost per MW derived from these data would not adequately predict the cost for servicing a new marginal substation. A relationship between age of a substation and the amount of maintenance needed was established by regressing the labor costs on the age of substation as shown in the equation below:

$$Labor\ Costs\ (\$/MW) = a + b * Age\ of\ Substation + error\ term$$

In order to adjust the substation maintenance cost from historical data to reflect the annualized value of the maintenance costs for a marginal substation, we computed the ratio between the projected labor cost at the average age of City Light's substations (30.5 years) and the annualized cost for a new substation over its economic life, which was found to be equivalent to the projected labor costs at age 14 years. Using the estimated coefficients from the equation above this ratio was found to be 1.485. The age adjustment factor is the reciprocal of this ratio and is

0.673, which was first derived in COSACAR 1993-1994 and has been used in every cost of service study since then.

The three year average is divided by the substation capacity to obtain the annual O&M per MW.

Table 3.23: Substation O&M Costs

		FERC #	2010	2011	2012
1	Load Dispatching	58101	$2,721,291	$2,668,213	$2,841,064
2	Distribution Substation Equipment	58201	3,850,764	4,112,808	4,580,205
	Maintenance of Station Equipment	59201	1,678,120	1,669,648	1,635,974
	Age Adjustment Factor		0.673	0.673	0.673
3	Maintenance of Station Equipment, Adj.		1,129,375	1,123,673	1,101,010
4	Maintenance of Distribution Structures	59101	838,380	1,260,197	1,649,168
	Total (1+2+3+4)		8,539,810	9,164,891	10,171,447
	Total in $2012		**$9,034,303**	**$9,397,614**	**$10,171,447**
	Three year average				$9,534,454
	Substation Capacity (MW)	2,458			
	Annual O&M, $2012/MW				**$3,879**

Total Substation Costs

Total substation costs for 2015 and 2016 are shown in **Tables 3.24** and **3.25**. These calculations are similar to total in service area transmission costs and are based on the following formula:

$$\frac{(Capital\ Costs/MW + O\&M\ Costs/MW) * Inflation * Class\ Coincident\ Peak\ Load * Subst\ Capacity}{Total\ Service\ Territory\ Peak\ Load}$$

where capital costs are either for network or non-network.

Similar to the calculations for in service area transmission costs, $/MW costs are based on the theoretical total capacity, which exceeds the load actually placed on substations. Thus, to get costs for actual substation usage by a particular class, the $/MW cost of total capacity is multiplied by the class coincident peak load and that result is multiplied by the substation capacity divided by the system peak load.

Table 3.24: 2015 Substation Costs

Network Capital Costs $2012/MW				$9,466			
Non-network Capital Costs $2012/MW				$8,833			
O&M Costs $2012/MW				$3,879			
Total Substation Capacity MW				2,458			
2015 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,171.7	525.5	150.6	257.0	115.0	117.1	6.6
Network	190.1	13.8	19.8	77.1	79.3		
Service Territory	1,361.8						
2015 Substation Costs					**$2015 inflation adjustment =**		**1.05786**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$28,440,993	$12,755,588	$3,654,514	$6,238,144	$2,790,394	$2,842,635	$159,718
Network	$4,843,543	$351,589	$505,565	$1,965,634	$2,020,754		
Service Territory	$33,284,536	$13,107,177	$4,160,080	$8,203,778	$4,811,148	$2,842,635	$159,718

Table 3.25: 2016 Substation Costs

Network Capital Costs $2012/MW				$9,466			
Non-network Capital Costs $2012/MW				$8,833			
O&M Costs $2012/MW				$3,879			
Total Substation Capacity MW				2,458			
2016 Coincident Peak Load (MW)							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,177.2	525.2	152.4	260.6	115.9	117.2	5.9
Network	191.9	15.9	20.8	76.2	79.0		
Service Territory	1,369.1						
2016 Substation Costs					**$2016 inflation adjustment =**		**1.08372**
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$29,115,382	$12,989,619	$3,768,947	$6,445,743	$2,865,913	$2,898,490	$146,669
Network	$4,983,765	$412,948	$540,776	$1,977,659	$2,052,382		
Service Territory	$34,099,147	$13,402,567	$4,309,723	$8,423,402	$4,918,295	$2,898,490	$146,669

3.4.3. Wires and Related Equipment

Wires and related equipment transport power over 26 kV lines (for non-network customers) or 13 kV lines (for network customers) from substations to the customer transformer, as well as from the customer transformer to the meter through a line called the service drop. Revenue requirements for wires and related equipment are assigned directly to non-network and network customers in the functionalization of revenue requirements (see Chapter 2).

Wires and Related Equipment Capital Costs

Tables 3.26 and **3.27** present the costs associated with wires and related equipment for non-network and network portions of the system, respectively. The calculation of per unit capital costs is similar to that for substations: the total capital cost for non-network/network is divided by capacity to obtain the cost per MW, which is then multiplied by the annualization factor and adjusted for losses.

Table 3.26: Non-network Wires and Related Equipment Capital Cost

Item	Labor Cost	Unit Material Cost	Total Labor & Material Cost	System Quantity	Total Cost
Anchor	$485	202	686	19,157	$13,150,165
Pipe brace anchor	$728	332	1,060	5,560	$5,893,094
Sectionalizers	$730	1,003	1,733	194	$336,207
600 amp OH switch	$5,110	5,143	10,253	1,394	$14,292,143
1200 amp OH switch	$6,327	8,565	14,892	212	$3,157,093
Capacitor	$0	0	0	48	$0
Cutouts	$730	115	845	6,190	$5,227,730
Cutouts with limiters	$730	464	1,194	1,224	$1,461,244
< 29' pole	$966	448	1,414	575	$813,023
30-35' pole	$966	723	1,690	14,603	$24,675,863
36-40' pole	$966	723	1,690	11,668	$19,716,357
41-45' pole	$966	1,041	2,007	18,161	$36,457,259
46-50' pole	$966	1,405	2,371	32,923	$78,058,020
51-55' pole	$966	1,535	2,501	6,535	$16,345,075
56-60' pole	$1,208	1,934	3,142	3,155	$9,914,247
61-70' pole	$1,208	1,264	2,472	2,106	$5,205,792
71'+ pole	$1,208	1,432	2,640	881	$2,325,837
#4 bare copper wire/ft, 1 phase	$18	2	20	4,131,879	$83,215,005
#4 bare copper wire/ft, 3 phase	$41	5	45	1,533,239	$69,742,868
397 ACSR, 3 phase, 600 amp	$52	5	57	2,834,550	$162,314,061
954 ACSR, 3 phase, 1200 amp	$68	14	82	679,606	$55,854,788
954 ACSR, 34 kV	$68	15	84	20,625	$1,728,163
1/0 triplex; inc open 2-#2 & 1-#4	$5	1	6	5,198,932	$30,964,798
1/0 quadplex	$5	2	7	269,038	$1,823,461
1/0 27 kV UG inc duct, trench, vault	$310	273	583	2,320,610	$1,352,601,106
1000 kCM UG inc duct, trench & vault	$405	397	802	539,582	$432,735,726
2-1000kCM UG inc duct, trench & vault	$421	483	903	149,479	$135,027,058
Handholes, ave 233 & 444	$4,095	3,726	7,821	9,290	$72,653,937
Manholes, 712	$21,657	22,979	44,636	162	$7,231,009
Vaults, ave, 577, 612, 814 & 818	$27,328	27,200	54,528	7,424	$404,812,312
Pads, ave	$2,736	2,051	4,787	993	$4,753,690
PMH5 switch	$25,352	57,054	82,406	21	$1,730,530
PMH5 E switch	$25,352	57,054	82,406	32	$2,636,997
PMH 9 switch	$22,378	31,273	53,651	99	$5,311,494
PMH10 switch	$24,865	30,063	54,928	24	$1,318,272
PMH12 switch	$21,135	31,560	52,695	37	$1,949,732
UG terminations, ave	$3,946	2,648	6,594	3,112	$20,521,833
J Boxes, ave	$1,547	1,082	2,629	11,669	$30,675,323
Total in $2012					**$3,116,631,309**
Total Capacity MW					5,432
Annualization factor					0.04019
Loss Factor					0.82%
Annual Capital Costs $2012/ MW					**$23,247**

Table 3.27: Network Wires and Related Equipment Capital Cost

	Per Unit Cost	# of Units	Total Cost
System Man Hole/Vaults	$273,664	1,374	$376,014,119
System Hand Holes	109,663	470	51,541,670
System Ducts	2,470	302,196	746,390,960
System Primary Feeder Cable	16,920	4,672	79,046,301
System Secondary Cables	10,006	1,881	18,821,323
Service Cables	10,006	465	4,652,849
Cable Limiters	99	43,179	4,265,896
Secondary Bus Bars	4,650	1,163	5,408,310
Total in $2012			**$1,286,141,427**
Total Capacity MW			660
Annualization factor			0.05027
Loss Factor			0.82%
Annual Capital Costs $2012/ MW			**$98,773**

Wires and Related Equipment O&M Costs

Table 3.28 presents the annual O&M costs for non-network service for the years 2010 through 2012, along with the three-year average. The costs for non-network service include service for First Hill and the University District, which have some characteristics of network service but are considered non-network for the purposes of rate making. In FERC records, O&M costs for First Hill and the University District are combined with downtown network costs and must be divided using proportion of total network load. In 2012, downtown network load comprised 85% of total network load, while First Hill and the University District comprised the remaining 15%. Thus, the O&M costs of First Hill and the University District areas are estimated to be 15% of total network O&M costs.

Table 3.29 presents the annual O&M costs for network service for the years 2010 through 2012, as well as the three-year average. As mentioned above, the load in the downtown network accounted for 85% of the total of all network loads in 2012 so the total network cost data were adjusted by this percentage to estimate the annual O&M costs for the downtown network. To get annual O&M costs per MW we divide the three year average total non-network or network annual costs in $2012 by the non-network or network capacity.

Table 3.28: Non-network O&M Costs-Wires and Related Equipment

FERC Code	FERC #	2010	2011	2012
Non-network Costs				
INSP TEST & PATROL OH DIST LIN	58352	$51,964	$457,456	$1,483,587
OH LINE ENGR EXP	58359	18,900	156,749	175,163
CLEAR TREES & TRIM BRUSH OH LI	59350	3,923,058	2,690,600	4,647,191
MAINT POLES CONDCTRS & SERVICE	59352	4,484,811	7,086,558	5,788,040
INSP & TEST UG DIST	58462	984,669	1,181,950	1,439,719
UG ENGR LINE EXP	58469	21,930	48,169	116,451
MAINT NON-ELECT UG EQUIP	59460	379,676	601,127	730,261
MAINT ELECT UG EQUIP	59462	2,847,853	2,647,729	3,292,892
Subtotal		**$12,712,863**	**$14,870,338**	**$17,673,302**
Network Costs (First Hill and U District 15.0%)				
INSPECT & TEST NETWORK UG DIST	58442	$223,055	$264,050	$253,352
MAINT NETWORK UG LINES	59440	1,151,206	436,861	2,188
MAINT NETWORK UG EQUIP	59442	972,865	695,964	770,155
MISC NETWK UG DIST SYS EXP	58841	138,859	22,534	3,639
Subtotal		2,485,986	1,419,410	1,029,334
Subtotal x 15.0%	**15%**	**$372,898**	**$212,911**	**$154,400**
Total Non-network Rate Classes O&M Expenses		13,085,761	15,083,249	17,827,702
Totals in $2012		**$13,843,483**	**$15,466,255**	**$17,827,702**
Three Year Average				$15,712,480
Total Capacity MW				5,432
Annual O&M Costs $2012/ MW				**$2,892**

Table 3.29: Network O&M Costs-Wires and Related Equipment

FERC Code	FERC #	2010	2011	2012
Network Costs (Downtown Network 85.0%)				
INSPECT & TEST NETWORK UG DIST	58442	$223,055	$264,050	$253,352
MAINT NETWORK UG LINES	59440	1,151,206	436,861	2,188
MAINT NETWORK UG EQUIP	59442	972,865	695,964	770,155
MISC NETWK UG DIST SYS EXP	58841	138,859	22,534	3,639
Subtotal		2,485,986	1,419,410	1,029,334
Subtotal x 85.0%	**85%**	**$2,113,088**	**$1,206,498**	**$874,934**
Total in $2012		**$2,235,445**	**$1,237,135**	**$874,934**
Three Year Average				$1,449,171
Total Capacity MW				660
Annual O&M Costs $2012/MW				**$2,196**

Service Drop Capital and O&M Costs

Service drops refer to the wires that lead from a customer transformer to the meter. Service drop capital costs vary by the configuration and size of wires (e.g., one or three phase service, ampere rating of the wires) and are computed per meter, not MW. **Table 3.30** presents the derivation of capital and O&M costs per meter. **Table 3.31** shows meter count projections for 2015 and 2016 and the derivation for those years of the total capital plus O&M costs for service drops.

Table 3.30: Service Drop Capital and O&M Costs per Meter

	Residential	Small	Medium	Large	High Demand
Non-network					
Annualized Capital Cost	$22,450,189	$2,533,874	$594,809	$265,392	$133,055
Number of Meters	343,688	39,886	2,593	87	11
Capital Cost per Meter	65.32	63.53	229.39	3,050.49	12,095.92
O&M Cost per Meter	5.62	5.62	5.62	7.65	7.65
$2012/Meter	**$70.94**	**$69.15**	**$235.01**	**$3,058.14**	**$12,103.58**
Network					
Annualized Capital Cost	$1,394,559	$305,635	$119,205	$812,139	
Number of Meters	16,322	3,107	527	53	
Capital Cost per Meter	85.44	98.37	226.20	15,323.38	
O&M Cost per Meter	5.62	5.62	5.62	7.65	
$2012/Meter	**$91.06**	**$103.99**	**$231.82**	**$15,331.04**	

Table 3.31: 2015 and 2016 Service Drop Costs

		Residential	Small	Medium	Large	High Demand
Non-network Costs $2012/Meter		70.94	69.15	235.01	3,058.14	12,103.58
Network Costs $2012/Meter		91.06	103.99	231.82	15,331.04	
2015 Costs for Service Drops				**$2015 inflation adjustment =**		**1.05786**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Number of Meters	399,730	356,895	40,156	2,572	95	12
$2015 Total Costs	**30,821,633**	**26,783,711**	**2,937,381**	**639,421**	**307,333**	**153,787**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
Number of Meters	20,294	16,450	3,244	541	59	
$2015 Total Costs	**3,031,043**	**1,584,643**	**356,863**	**132,669**	**956,868**	
2016 Costs for Service Drops				**$2016 inflation adjustment =**		**1.08372**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Number of Meters	420,024	373,345	43,400	3,113	154	12
$2016 Total Costs	**33,416,150**	**28,703,112**	**3,252,276**	**792,836**	**510,381**	**157,546**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
Number of Meters	20,294	16,450	3,244	541	59	
$2016 Total Costs	**3,105,131**	**1,623,376**	**365,586**	**135,912**	**980,257**	

Total Wires and Related Equipment Costs Including Service Drops

Total Wires and Related Equipment costs for 2015 and 2016 are shown in **Tables 3.32** and **3.33**. Costs for non-network classes are based on the following formula:

$$\frac{(Nonnet\ Capital\ Costs/MW + Nonnet\ O\&M\ Costs/MW) * Inflation * Class\ Coincident\ Peak\ Load * Nonnet\ Capacity}{Total\ Nonnetwork\ Peak\ Load} + Total\ Service\ Drops\ costs\ by\ class$$

Costs for network classes are based on the following formula:

$$\frac{(Netw\ Capital\ Costs/MW + Netw\ O\&M\ Costs/MW) * Inflation * Class\ Coincident\ Peak\ Load * Netw\ Capacity}{Total\ Network\ Peak\ Load} + Total\ Service\ Drops\ costs\ by\ class$$

Table 3.32: 2015 Total Wires and Related Equipment Costs

Non-network		**Network**	
Capital Costs, $2012/MW	23,247	Capital Costs, $2012/MW	98,773
O&M Costs, $2012/MW	2,892	O&M Costs, $2012/MW	2,196
Total Capacity MW	5,432	Total Capacity MW	660

2015 Coincident Peak Load (MW)

	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,171.7	525.5	150.6	257.0	115.0	117.1	6.6
Network	190.1	13.8	19.8	77.1	79.3		
Service Territory	1,361.8						

2015 Wires and Related Equipment Costs — **$2015 inflation adjustment = 1.05786**

	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$181,033,029	$94,152,477	$22,238,736	$33,586,242	$15,044,828	$15,167,190	$843,555
Network	$73,525,914	$6,701,810	$7,715,062	$28,741,301	$30,367,741		
Service Territory	$254,558,943	$100,854,287	$29,953,798	$62,327,544	$45,412,569	$15,167,190	$843,555

Table 3.33: 2016 Total Wires and Related Equipment Costs

Non-network		**Network**	
Capital Costs, $2012/MW	23,247	Capital Costs, $2012/MW	98,773
O&M Costs, $2012/MW	2,892	O&M Costs, $2012/MW	2,196
Total Capacity MW	5,432	Total Capacity MW	660

2016 Coincident Peak Load (MW)

	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	1,177.2	525.2	152.4	260.6	115.9	117.2	5.9
Network	191.9	15.9	20.8	76.2	79.0		
Service Territory	1,369.1						

2016 Wires and Related Equipment Costs — **$2016 inflation adjustment = 1.08372**

	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Non-network	$187,299,169	$97,356,920	$23,172,226	$34,860,410	$15,657,541	$15,476,885	$775,187
Network	$75,323,111	$7,607,260	$8,201,781	$28,793,472	$30,720,598		
Service Territory	$262,622,280	$104,964,180	$31,374,006	$63,653,883	$46,378,139	$15,476,885	$775,187

3.4.4. Customer Transformers

Customer transformers convert electricity from feeder line voltage (13 or 26 kV) to a lower customer-level voltage and are sized to maximum demand. Larger customers often have one (or more) dedicated transformers that are not shared with other customers. Smaller customers typically share one transformer.

One challenge in a marginal cost study is that there is no single standard type of transformer. Transformers in the City Light system come in many different sizes and might be pole-mounted, submersible or network, and each transformer type carries a different unit cost. In this study, Residential and Small General Service classes assume a typical transformer.

However, the Medium, Large and High Demand General Service cost estimates employ a more refined methodology, used since the *1989-1990 COSACAR*. For Medium, Large and High Demand, the number of transformers in each size category needed to serve each individual customer was estimated using current engineering design guidelines and each customer's 2012 maximum recorded demand. The frequency of each transformer type appears in column (E) of **Tables 3.39** through **3.41**.

In general, transformers are assigned such that the transformer rating exceeds the customer's maximum demand. An exception to this rule is residential transformers. Ambient temperature affects the loading of transformers; the actual capacity of the transformer can be half again or more as great as its nameplate rating on a very cold day. Since residential customers typically realize their maximum demand when the weather is coldest, residential transformers are undersized. The expected maximum demand on residential transformers typically exceeds the transformer nameplate rating by 50%, or a loading versus rating of 150%. In contrast, transformers for small general service customers are assigned a loading versus rating of 100%.

For network customers, redundant transformer capacity is installed to increase reliability. In a typical network configuration, three lines are brought to three transformers sized such that service can be maintained with any two of the three lines in service. By loading three transformers in a vault to 67% (i.e., 2/3) capacity each, if one goes out the remaining two will still be able to carry the entire load. This "N-1 rule" is followed for the network transformer assignments made in this study by assuming that the number of transformers needed to carry the load in the network areas is augmented by one in order to provide increased reliability.[3]

Transformer Costs and Cost-Related Factors

Table 3.34 summarizes the total annual cost per kW of providing transformation services to each of the customer classes. Background information related to developing the costs in **Table 3.34** is presented in **Tables 3.35** and **3.36**. The actual calculations of the transformer costs summarized in **Table 3.34** are developed in **Tables 3.37** through **3.41.**

[3] Smaller network customers were assigned using this "N-1" capacity approach but were assigned fictitious transformer capacities and converted to the minimum network size of 500 kVA.

Table 3.34: Summary of Transformer Total Costs, $2012

Customer Class	$/kW/Year
Residential	$3.25
Small	$4.52
Medium, Combined	$9.27
Medium, Non-network	$5.05
Medium, Network	$25.19
Large, Combined	$7.70
Large, Non-network	$2.72
Large, Network	$15.51
High Demand	$1.63
Streetlights	$4.52

Transformer Capital Costs

The capital costs of transformers include the current purchase price of the transformer and associated equipment and materials, the labor to set the transformer, an allotment for inventory reserves, and an adjustment for losses through the transformer. The purchase prices used in this analysis are averages of recent actual purchases. The purchase price for each size and type of transformer, network protector and ancillary equipment, including sales tax, is shown in **Table 3.35**. The labor to install the transformer includes the cost of setting the transformer, testing it, installing related equipment when needed (such as network protectors, disconnect switches, etc.) and, in some cases, assembling the transformer. The customer is not billed for any of these tasks except through rates, so this labor is included in marginal transformer costs. However, the labor cost involved in connecting the transformer to the customer's service and the distribution system is recovered through a direct installation charge, so the cost for that labor is not included as part of marginal transformer costs. Material costs including taxes (**Tables 3.37-3.41)** are used to estimate total transformer costs per kW per year for each customer class. The expected life of transformers is 30 years, which results in an annualization rate of .05027.

Table 3.35: Purchase Cost of Transformers, Network Protectors and Ancillary Equipment (including sales tax), 2012 data

Transformer Type	Transformers	Network Protectors	Ancillary Equipment	Installation Cost	Total Cost
25 kVA, Overhead	$2,049		$259	$973	$3,281
25 kVA, Underground	$3,682		$388	$1,460	$5,530
50 kVA, Overhead	$2,715		$323	$973	$4,012
50 kVA, Underground	$5,616		$485	$1,460	$7,560
75 kVA, Overhead	$3,989		$378	$973	$5,341
75 kVA, Underground	$5,556		$568	$1,460	$7,584
100 kVA, Overhead	$4,910		$378	$973	$6,261
100 kVA, Underground	$6,531		$568	$1,460	$8,558
167 kVA, Overhead	$6,928		$769	$1,217	$8,914
167 kVA, Underground	$9,667		$1,153	$1,825	$12,645
750 kVA Commercial Subway	$40,932		$1,236	$8,951	$51,120
1000 kVA Commercial Subway	$48,091		$1,236	$8,951	$58,278
1500 kVA Commercial Subway	$63,111		$1,236	$8,951	$73,298
2000 kVA Commercial Subway	$74,477		$1,236	$8,951	$84,664
2500 kVA Commercial Subway	$88,005		$1,236	$8,951	$98,192
5000 kVA Commercial Subway	$134,617		$1,236	$8,951	$144,804
7500 kVA Commercial Subway	$171,867		$1,236	$8,951	$182,054
15000 kVA Commercial Subway	$373,793		$1,236	$8,951	$383,980
500 kVA Network	$43,495	$25,780	$8,847	$23,072	$101,194
750 kVA Network	$47,119	$25,780	$8,892	$23,072	$104,863
1000 kVA Network	$57,289	$33,630	$12,688	$53,853	$157,460
1500 kVA Network	$76,444	$44,847	$13,145	$54,583	$189,020
2000 kVA Network	$89,046	$56,849	$13,181	$54,583	$213,660

Transformer O&M Costs

Reported O&M costs vary year to year, so a three year average from 2010 to 2012, adjusted for inflation, is used to calculate total O&M costs. O&M costs are reported in FERC account 595 as a system total, not by specific customer classes. In order to determine the class-specific O&M, we express class-specific O&M as a function of capital by using an O&M factor--which is total O&M as a percentage of total capital costs. Class-specific O&M is then determined by multiplying the capital costs for a given class by the O&M factor. However, not all transformers incur O&M expenses; transformers of 167 kVA and smaller receive no maintenance, and are simply replaced on failure. Therefore, in this analysis, annual O&M costs are applied only to the transformers equal to or larger than 500 kVA and the total capital costs used to calculate the O&M factor are adjusted accordingly. For this analysis, the O&M factor is estimated as 27.65% of the annual capital cost. O&M costs for transformers have risen steadily and consistently relative to capital costs over the last several years.

Class Load Factors Used in Transformer Cost Calculation

Similar to other areas of distribution costs, we first determine the cost per MW of transformers for each class. However, in the case of transformers, we arrive at a total cost by using the non-coincident maximum demand, or connected load, instead of the peak demand. This is because transformers are installed in order to meet customer specific peak loads, regardless of a system peak.

Medium, Large and High Demand classes have demand meters; therefore, 2012 connected loads can be obtained directly from the billing records. For Residential and Small General Service classes, load factors are used to estimate 2012 non-coincident maximum demand (connected load). Load factors are necessary for all classes to forecast future connected load. **Table 3.36** details load factor assumptions.

Table 3.36: 2012 Load Factors by Customer Class

Customer Class	Adjusted Annual MWH	Connected Load, MW		Load Factor	
Residential	3,106,834	927.6	(1)	0.3813	(4)
Residential Non-network	3,025,955	905.3	(2)	0.3805	
Residential Network	80,879	22.3	(3)	0.4130	
Small	1,189,198	352.4	(1)	0.3841	(4)
Small Non-network	1,045,785	312.9	(2)	0.3805	
Small Network	143,413	39.5	(3)	0.4130	
Medium	2,453,233	721.8		0.3869	(4)
Medium Non-network	1,904,956	570.6		0.3800	(4)
Medium Network	548,277	151.1		0.4130	(4)
Large	1,480,262	368.3		0.4576	(4)
Large Non-network	873,038	224.9		0.4420	(4)
Large Network	607,223	143.4		0.4821	(4)
High Demand	1,131,433	245.0		0.5257	(4)
Streetlights	91,879	20.9		0.5000	(5)

Notes:

(1) Sum of Non-network and Network.

(2) Because customers in these classes do not have demand meters, connected load must be estimated by taking adjusted annual MWh divided by the number of hours in the year (8760 or 8784 for a leap year) divided by load factor.

(3) Residential and Small Network customers are assumed to have same load factor as Medium Network customers.

(4)The load factors are calculated by first dividing the adjusted annual MWh by 8760 (8784 for 2012, a leap year) to get average MW and then dividing that by the class non-coincident maximum demand (i.e., connected load) from 2012 billing data, shown in the table.

(5) Streetlights are on for 12 hours per day, therefore, their load factor is assumed to be 0.5.

Special Transformer Information by Class

Consistent with previous Cost of Service analyses, the Residential and Small General Service non-network load factors are assumed to be 0.3805. The transformer loadings for residential customers are estimated using the following formula:

$$Maximum\ Demand = 12kW + 0.0003(Annual\ kWh)$$

where $Annual\ kWh$ is the total energy for all the customers on that transformer. For each 1,000 kWh of added annual load on a transformer, the maximum demand increases by 0.3 kW.

Since $Load\ Factor = Average\ kW / Peak\ \ kW$, then
$Marginal\ Load\ Factor = Change\ in\ Average\ kW / Change\ in\ Peak\ kW = \frac{1{,}000\ kWh}{8{,}760\ h*0.3\ kW} = 0.3805$
In the absence of adequate load research, the transformer group load factor for the Small General Service class has been assumed to be 0.3805 as well.

All customers in the Medium, Large, and High Demand General Service classes have demand meters, so load factors can be computed directly from billing data.[4] The load factor is calculated for each class by dividing 2012 average class energy consumption in MWh by 8,784 hours and then dividing the result by the total class non-coincident maximum demand for 2012.[5]

Streetlights do not have meters and are served at distribution voltage (assumed to be 26 kV) by short service drops from nearby transformers. For costing purposes, streetlights are treated the same as Small General Service customers; they have transformer capacity assigned according to the same design rules, and the same unit cost of transformer capacity.

Streetlights are on for 12 hours per day, therefore their load factor is assumed to be 0.5.

Transformer Costs by Customer Class
In **Tables 3.37** through **3.41**, all of the factors discussed in the preceding sections are combined to yield total annual transformer costs per kW for each customer class. Annual transformer costs per kW for Residential and Small General Service (**Tables 3.37** and **3.38)** are derived as follows:

1. Compute weighted average costs of transformers, ancillary equipment and materials, and installation for a 50 kVA transformer using the percentages of the overhead and underground transformers in the system.
2. Adjust transformer costs for losses.
3. Compute the Annualized Capital Cost (ACC) by summing the transformer costs (adjusted for losses), and ancillary equipment and materials costs, then multiplying this sum by the inventory reserve factor, adding installation costs to this amount, and finally, multiplying this total by the annualization factor.
4. Compute the Levelized Capital Cost (LCC) by dividing ACC by the transformer size multiplied by the loading rate (i.e., the percentage of loading vs rating).

For Medium, Large, and High Demand General Service classes, transformers are assigned based on customer demand and service environment data from 2012. Estimates of the number of transformers in each size category are shown in the "Frequency" column. The annual cost per kW for each of these classes, seen in **Tables 3.39**, **3.40**, and **3.41**, is derived as follows:

1. For transformers of 25-167 kVA, the weighted average costs of transformers, ancillary equipment and materials, and installation are computed using the percentages of the overhead and underground transformers in the system. For larger size transformers, costs are taken directly from **Table 3.35**.

[4] Unlike Residential and Small General Service customers, where customers are grouped to one transformer, the rule for Medium, Large, and High Demand customers is at least one transformer to one customer. As a consequence, it is the load factor of each individual customer (or on each individual meter) that is relevant.
[5] In a non-leap year 8,760 hours should be used.

2. The Annualized Transformer Cost (ATC) is calculated for each transformer size by multiplying the number of transformers by their respective transformer cost. These are summed together and the sum is multiplied by the inventory reserve factor and annualization factor to get the total ATC.
3. ATC adjusted for losses (denoted as AFL in tables) is computed by multiplying it by a losses percentage, which varies for non-network and network.
4. Similarly, to get non-network and network Annualized Materials and Installation Cost (AMIC) we first multiply the number of transformers of a particular size by their respective material costs to get the total material costs for each transformer size, then we add these total costs together and multiply this sum by the inventory reserve factor. Next, we multiply the number of transformers of a particular size by their respective installation costs and add them together. Lastly, we sum total material costs adjusted with a reserve factor and total installation costs and multiply this sum by the annualization factor. To get AMIC for the total system we add AMIC for non-network and network together.
5. Annualized Capital Cost (ACC) is the sum of AFL and AMIC.
6. Levelized Capital Cost (LCC) is derived by dividing ACC by the class non-coincident maximum demand.
7. Annual O&M cost (AOM) is calculated by multiplying LCC by the O&M factor and, in the case of the Medium General Service class, by the percent of total capital cost that is subject to O&M. (100% of transformer capital costs are subject to O&M in the Large and High Demand classes.)
8. Finally, AOM and LCC are added together to obtain the total annual transformer cost per kW for each class.

Table 3.37: Residential Class Transformer Cost, $2012

Total Residential Transformer Cost = $3.25 /kW/year

	Transformer Size (kVA)	Transformer Cost	Ancillary Equipment and Material Cost	Installation Cost	Frequency (#)	Total Capacity (kVA)
	(A)	(B)	(C)	(D)	(E)	(F)
(1)	50	$3,295	$355	$1,071	n.a.	n.a.

Assumptions:

(a)	Inventory Reserve Factor	1.0175
(b)	Economic Life	30
(c)	Annualization Factor	0.0502708
(d)	Loading vs. Rating	150%
(e)	Losses	1.77%
(f)	O&M as % of Annual Capital Cost	0%
(g)	50 kVA OH Transformer	$2,715
(h)	50 kVA UG Transformer	$5,616
(i)	50 kVA OH Ancillary Equipment Cost	$323
(j)	50 kVA UG Ancillary Equipment Cost	$485
(k)	50 kVA OH Labor & Installation Cost	$973
(l)	50 kVA UG Labor & Installation Cost	$1,460
(m)	% Overhead transformers	80%

Annual Capital Cost Calculations:

Transformer Cost (TC) = (B) =	(g) * (m) + (h) * [1-(m)]	$3,295	
Ancillary Equipment and Material Cost (C) =	(i) * (m) + (j) * [1-(m)]	$355	
Installation Cost (D) =	(k) * (m) + (l) * [1-(m)]	$1,071	
Adjusted for Losses (TCAFL) =	TC * {1 / [1 - (e)]}	$3,355	
Annualized Capital Cost (ACC) =	{(a)*[(TCAFL)+ (C)] + (D)} *(c)	$244	/year
Levelized Capital Cost (LCC) =	ACC / [(A) * (d)]	$3.25	/kW/year

Table 3.38: Small General Service Class and Streetlight Transformer Cost, $2012

	Small General Service Class and Streetlight Transformer Cost =			**$4.52 /kW/year**		
	Transformer Size (kVA)	**Transformer Cost**	**Ancillary Equipment and Material Cost**	**Installation Cost**	**Frequency (#)**	**Total Capacity (kVA)**
	(A)	(B)	(C)	(D)	(E)	(F)
(1)	50	$3,005	$339	$1,022	n.a.	n.a.
Assumptions:						
(a)	Inventory Reserve Factor			1.0175		
(b)	Economic Life			30		
(c)	Annualization Factor			0.0502708		
(d)	Loading vs. Rating			100%		
(e)	Losses			2.31%		
(f)	O&M as % of Annual Capital Cost			0%		
(g)	50 kVA OH Transformer Cost			$2,715		
(h)	50 kVA UG Transformer Cost			$5,616		
(i)	50 kVA OH Ancillary Equipment Cost			$323		
(j)	50 kVA UG Ancillary Equipment Cost			$485		
(k)	50 kVA OH Labor & Installation Cost			$973		
(l)	50 kVA UG Labor & Installation Cost			$1,460		
(m)	% Overhead transformers			90%		
Annual Capital Cost Calculations:						
Transformer Cost (TC) = (B) =			(g) * (m) + (h) * [1-(m)]		$3,005	
Ancillary Equipment and Material Cost (C) =			(i) * (m) + (j) * [1-(m)]		$339	
Installation Cost (D) =			(k) * (m) + (l) * [1-(m)]		$1,022	
Adjusted for Losses (TCAFL) =			TC * {1 / [1 - (e)]}		$3,077	
Annualized Capital Cost (ACC) =			{(a) *[(TCAFL)+ (C)] + (D)} * (c)		$226	/year
Levelized Capital Cost (LCC) =			ACC / [(A) * (d)]		$4.52	/kW/year

Table 3.39: Medium General Service Class Transformer Cost, $2012

Medium General Service Transformer Cost, Combined =				**$9.27**	**/kW/year**
Medium General Service Transformer Cost, non-Network =				**$5.05**	**/kW/year**
Medium General Service Transformer Cost, Network =				**$25.19**	**/kW/year**

	Transformer Size (kVA)	**Transformer Cost**	**Ancillary Equipment and Material Cost**	**Installation Cost**	**Frequency (#)**	**Total Capacity (kVA)**
	(A)	(B)	(C)	(D)	(E)	(F)
Small (pole/sub)						
(1)	25	$2,375	$285	$1,071	1,686	42,150
(2)	50	$3,295	$355	$1,071	2,946	147,300
(3)	75	$4,302	$416	$1,071	1,209	90,675
(4)	100	$5,234	$416	$1,071	588	58,800
(5)	167	$7,476	$846	$1,338	822	137,274
% Overhead transformers		80%			**Total**	**476,199**
Commercial Subway						
(6)	750	$40,932	$1,236	$8,951	147	110,250
(7)	1,000	$48,091	$1,236	$8,951	60	60,000
(8)	1,500	$63,111	$1,236	$8,951	32	48,000
Network					**Total**	**218,250**
(9)	500	$43,495	$34,627	$23,072	512	256,000
(10)	750	$47,119	$34,672	$23,072	63	47,250
					Total	**303,250**

Assumptions:		**Common**	**Non-network**	**Network**
(a)	Inventory Reserve Factor	1.0175		
(b)	Economic Life, years	30		
(c)	Annualization Factor	0.0502708		
(d)	Losses		0.98%	0.44%
(e)	Class Noncoincident Max Demand, kW	721,773	570,643	151,130
(f)	O&M as % of Annual Capital Cost	27.65%		
(g)	% of Capital Cost Subject to O&M	64.69%	25.50%	100.00%

Annual Capital and O&M Costs Calculations:		**Combined**	**Non-network**	**Network**
Annualized Transformer Cost (ATC) = {[(a) * SUM(1...10)(B * E)]} * (c)				
	$/ year =	$3,288,842	$1,997,918	$1,290,924
Adj. for Losses (AFL) =	ATC / (1-d) [$/kW/yr]	$3,314,262	$2,017,691	$1,296,571
Annualized Material & Installation Cost (AMIC) = {(a)*SUM(1...10)(C*E)+SUM(1...10)(D*E)}*(c)				
	$/ year =	$2,361,415	$675,907	$1,685,508
Ann. Cap. Cost (ACC) =	AFL+AMIC [$/ year]	$5,675,677	$2,693,598	$2,982,079
Levelized Cap.Cost (LCC) =	ACC/(e) [$/kW/yr]	$7.86	$4.72	$19.73
Ann.O&M (AOM) =	LCC * (f) * (g) [$/kW/yr]	$1.41	$0.33	$5.46
Total Cost =	LCC + AOM [$/kW/yr]	**$9.27**	**$5.05**	**$25.19**

Table 3.40: Large General Service Class Transformer Cost, $2012

Large General Service Transformer Cost, Combined =				**$7.70**	**/kW/year**
Large General Service Transformer Cost, Non-Network =				**$2.72**	**/kW/year**
Large General Service Transformer Cost, Network =				**$15.51**	**/kW/year**

	Transformer Size (kVA)	Transformer Cost	Ancillary Equipment and Material Cost	Installation Cost	Frequency (#)	Total Capacity (kVA)
	(A)	(B)	(C)	(D)	(E)	(F)
Commercial Subway						
(1)	750	$40,932	$1,236	$8,951	4	3,000
(2)	1,000	$48,091	$1,236	$8,951	0	0
(3)	1,500	$63,111	$1,236	$8,951	39	58,500
(4)	2,000	$74,477	$1,236	$8,951	31	62,000
(5)	2,500	$88,005	$1,236	$8,951	10	25,000
(6)	5,000	$134,617	$1,236	$8,951	12	60,000
(7)	7,500	$171,867	$1,236	$8,951	5	37,500
					Total	**246,000**
Network						
(8)	500	$43,495	$46,276	$53,853	3	1,500
(9)	750	$47,119	$46,298	$53,853	39	29,250
(10)	1,000	$57,289	$46,318	$53,853	27	27,000
(11)	1,500	$76,444	$57,993	$54,583	102	153,000
(12)	2,000	$89,046	$70,030	$54,583	21	42,000
					Total	**252,750**

Assumptions:		**Common**	**Non-network**	**Network**
(a)	Inventory Reserve Factor	1.0175		
(b)	Economic Life, years	30		
(c)	Annualization Factor	0.0502708		
(d)	Losses		0.89%	0.40%
(e)	Class Non-coincident Max Demand, kW	368,264	224,867	143,397
(f)	O&M as % of Annual Capital Cost	27.65%		

Annual Capital and O&M Cost Calculations:	**Combined**	**Non-network**	**Network**
Annualized Transformer Cost (ATC) = {[(a)*SUM(1...12)(B*E)]}*(c)	$1,098,243	$423,968	$674,275
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr]	$1,104,728	$427,775	$676,953
Ann. Mat'l & Install (AMIC)={(a)*SUM(1...12)(C*E)+SUM(1...12)(D*E)}*(c)	$1,117,359	$51,834	$1,065,525
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year]	$2,222,087	$479,609	$1,742,478
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]	$6.03	$2.13	$12.15
Ann.O&M (AOM) = LCC * (f) [$/kW/yr]	$1.67	$0.59	$3.36
Total Cost = LCC + AOM [$/kW/yr]	**$7.70**	**$2.72**	**$15.51**

Table 3.41: High Demand General Service Class Transformer Cost, $2012

Total High Demand General Service Class Transformer Cost = $1.63 /kW/year						
	Transformer Size (kVA)	**Transformer Cost**	**Ancillary Equipment and Material Cost**	**Installation Cost**	**Frequency (#)**	**Total Capacity (kVA)**
	(A)	(B)	(C)	(D)	(E)	(F)
Commercial Subway						
(1)	5,000	$134,617	$1,236	$8,951	2	5,000
(2)	7,500	$171,867	$1,236	$8,951	0	7,500
(3)	15,000	$373,793	$1,236	$8,951	15	240,000
Assumptions:						
(a)	Inventory Reserve Factor			1.0175		
(b)	Economic Life, years			30		
(c)	Annualization Factor			0.0502708		
(d)	Losses			0.89%		
(e)	Class Non-coincident Max Demand, kW			245,001		
(f)	O&M as % of Annual Capital Cost			27.65%		
Annual Capital and O&M Cost Calculations:						
Annualized Transformer Cost (ATC) = {[(a) * SUM(1…3)(B * E)]} * (c)					$300,567	
Adj. for Losses (AFL) = ATC / (1-d) [$/kW/yr]					$303,266	
Ann. Mat'& Install (AMIC) = (a)*SUM(1…3)(C*E)+SUM(1…3)(D*E)}*(c)					$8,724	
Ann. Cap. Cost (ACC) = AFL+AMIC [$/ year]					$311,990	
Levelized Cap.Cost (LCC) = ACC/(e) [$/kW/yr]					$1.27	
Ann.O&M (AOM) = LCC * (f) [$/kW/yr]					$0.35	
Total Cost = LCC +AOM [$/kW/yr]					**$1.63**	

Total Transformer Costs

Table 3.42 presents total transformer costs for 2015 and 2016. Costs for non-network classes are based on the following formula:

$$Peak\ MW * Nonnetwork\ Transformer\ Cost/kW * Inflation * 1{,}000$$

where $Peak\ MW = Load\ MWh/Load\ Factor\ /8{,}760\ (or\ 8{,}784\ for\ a\ leap\ year)$.

Similarly costs for network classes are based on the following formula:

$$Peak\ MW * Network\ Transformer\ Cost/kW * Inflation * 1{,}000$$

where $Peak\ MW$ is defined as above.

Load data does not include losses and comes from **Tables 3.1** and **3.2**. The load factor data comes from **Table 3.36**.

Table 3.42: 2015 and 2016 Total Transformer Costs

		Residential	Small	Medium	Large	High Demand	Lights
Non-network Transformer Costs $2012/kW		$3.25	$4.52	$5.05	$2.72	$1.63	$4.52
Network Transformer Costs $2012/kW		$20.35*	$20.35*	$25.19	$15.51		
2015 Transformer Costs						**$2015 inflation adjustment =**	**1.05786**
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Load, MWh	8,156,323	3,064,864	1,062,355	1,916,508	919,789	1,124,315	68,493
Load Factor		0.3805	0.3805	0.3800	0.4420	0.5257	0.5000
Peak Load, MW	2,311	920	319	576	238	244	16
$2015 Total Costs	$8,940,033	$3,159,364	$1,524,600	$3,077,268	$684,199	$419,798	$74,803
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**		
Load, MWh	1,410,997	92,799	144,921	575,791	597,486		
Load Factor		0.4130	0.4130	0.4130	0.4821		
Peak Load, MW	366	26	40	159	141		
$2015 Total Costs	$7,976,629	$552,165	$862,292	$4,240,572	$2,321,599		
Total Service Territory	**$16,916,662**	**$3,711,529**	**$2,386,893**	**$7,317,840**	**$3,005,798**	**$419,798**	**$74,803**
2016 Transformer Costs				**$2016 inflation adjustment =**			**1.08372**
Total Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Load, MWh	8,190,141	3,064,069	1,072,909	1,937,438	925,887	1,127,827	62,011
Load Factor		0.3805	0.3805	0.3800	0.4420	0.5257	0.5000
Peak Load, MW	2,315	917	321	580	238	244	14
$2016 Total Costs	$9,181,246	$3,226,909	$1,573,073	$3,178,207	$703,642	$430,224	$69,190
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**		
Load, MWh	1,421,289	92,736	146,075	580,250	602,227		
Load Factor		0.4130	0.4130	0.4130	0.4821		
Peak Load, MW	368	26	40	160	142		
$2016 Total Costs	$8,208,288	$563,732	$887,976	$4,365,910	$2,390,670		
Total Service Territory	**$17,389,534**	**$3,790,640**	**$2,461,049**	**$7,544,117**	**$3,094,312**	**$430,224**	**$69,190**

Note: * Residential and Small network transformer costs are assumed to be an average of Medium and Large network transformer costs.

3.4.5. Meters

Like service drops, there are many kinds of meters assigned to the different classes. Meter O&M costs are the costs of maintaining and testing the meters. Meter capital costs are the cost of the meters themselves and the labor and non-labor cost of installation. Meter capital costs are annualized over the assumed economic life of the meters of 18 years and the cost of installation is annualized over 40 years. **Table 3.43** summarizes the $2012 annualized capital and O&M

costs per meter and presents the development of the total costs of meters by customer class for 2015 and 2016.

Table 3.43: 2015 and 2016 Total Meter Costs

Non-network		**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Annualized Capital Cost		$2,369,010	$651,637	$176,687	$20,342	$3,841
Number of Meters		343,688	39,886	2,593	87	11
$2012 Capital Cost per Meter		$6.89	$16.34	$68.14	$233.82	$349.18
$2012 O&M Cost per Meter		$3.01	$3.01	$3.01	$3,995.92	$3,995.92
Total $2012 Cost per Non-network Meter		$9.90	$19.34	$71.15	$4,229.74	$4,345.09
Network		**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Annualized Capital Cost		$123,655	$94,270	$35,910	$12,446	
Number of Meters		16,322	3,107	527	53	
$2012 Capital Cost per Meter		$7.58	$30.34	$68.14	$234.83	
$2012 O&M Cost per Meter		$3.01	$3.01	$3.01	$3,995.92	
Total $2012 Cost per Network Meter		$10.58	$33.35	$71.15	$4,230.75	
2015 Meter Costs					**$2015 inflation adjustment =**	**1.05786**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2015 Number of Meters	399,730	356,895	40,156	2,572	95	12
2015 Total Costs	$5,233,323	$3,737,712	$821,749	$193,578	$425,075	$55,208
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2015 Number of Meters	20,294	16,450	3,244	541	59	
2015 Total Costs	$603,384	$184,168	$114,441	$40,718	$264,057	
Service Territory	$5,836,707	$3,921,880	$936,190	$234,296	$689,132	$55,208
2016 Meter Costs					**$2016 inflation adjustment =**	**1.08372**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2016 Number of Meters	399,730	356,895	40,156	2,572	95	12
2016 Total Costs	$5,361,242	$3,829,073	$841,835	$198,310	$435,465	$56,558
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2016 Number of Meters	20,294	16,450	3,244	541	59	
2016 Total Costs	$618,132	$188,669	$117,238	$41,713	$270,511	
Service Territory	$5,979,374	$4,017,743	$959,074	$240,023	$705,976	$56,558

3.5. Customer Service Costs

Customer service costs are expenditures associated with serving City Light customers by collecting meter readings, processing customer bills, answering customer phone calls, opening and closing accounts, writing-off uncollectible bills and performing other customer service related work. **Table 3.44** provides 2012 data for each FERC program code associated with customer service.

Table 3.44: 2012 Customer Service Costs by FERC Code

FERC Code [1]	FERC #	2012
Revenue		
MISC SVC REV-MISC COML EQ RENT	45110	159,690
MISC SVC REV-ACCT CHANGE FEE(R	45130	1,234,468
MISC SVC REV-ACCT CHANGE FEE(C	45131	9,022
MISC SVC REV-RECONCT & FIELD C	45150	1,102,362
Total		**2,505,542**
Expenses		
METER READING SUPERVISION	90101	195,163
METER READING EXPENSES	90201	3,273,234
DISCON SERV NON-PAYMENT	90301	993,524
CR INVESTIGATIONS & RECORDS	90311	2,497,730
COLLECTING-LIGHT DEPT	90321	4,699,063
COL-CITY TREAS BNKS,AM EXPR	90341	2,003,182
CUST CONTR & ORDERS	90351	8,192,610
BILL REV ACCTG & MAILING	90361	3,650,268
UNCOLLECTIBLE ACCT-ELEC UTILTY [2]	90401	6,472,982
UNCOLLECTIBLE ACCT-SUNDRY SALE [2]	90403	1,574,983
MISC CUST ACCT EXP	90501	845,120
SUPERVISION-RESIDENTIAL	90701	65,464
SUPV-CMML & IND	90711	0
CUST ASST EXP- RESDL	90801	2,869,381
CUST ASST EXP-CMML& IND	90811	1,695,637
MISC CUST SERV & INFO EXP	91001	776,543
GENERAL ADVERTISING EXPENSES*	93010	262,268
Total		**40,067,150**

1. FERC Names are listed as they appear in the system; some line items may look abbreviated or truncated.
2. Value is a four year average (2008-2011) because 2012 was not indicative of normal operations.

The marginal customer cost per meter is a sum of per meter costs associated with each FERC program code listed in **Table 3.44**. For each customer class, total customer costs were calculated by first deriving 2012 marginal customer costs per meter, inflating them to $2015 and $2016, and then multiplying them by the number of meters projected for 2015 and 2016.

3.5.1. Meter Cost Allocation Factors

Each of the customer costs listed in **Table 3.44** was allocated among customer classes and then divided by the number of meters to get per meter costs. **Table 3.45** summarizes the 2012 customer data used to derive the allocation factors shown in **Table 3.47**, which were used in allocating customer costs across customer classes.

Table 3.45: 2012 Customer Information Data

	Total	Residential	Small	Medium	Large	High Demand
Meter Count	406,274	360,010	42,993	3,120	140	11
Non-network		343,688	39,886	2,593	87	11
Network		16,322	3,107	527	53	
Customer Count	391,606	356,405	32,255	2,803	134	9
Bills Issued Count (Annual Average)	2,698,474	2,398,935	263,334	34,451	1,645	109
Annual Energy Consumption (MWh)	9,360,960	3,106,834	1,189,349	2,447,000	1,486,343	1,131,433
Payment Method						
Cash or Check	$483,404,428	$155,065,347	$66,446,010	$129,996,225	$84,220,532	$47,676,315
Credit Card	$40,893,261	$32,690,492	$4,789,057	$2,559,538	$854,175	0
Metavante*	$115,148,228	$56,000,511	$10,789,544	$21,792,187	$9,766,190	$16,799,796
Interfund transfer	$12,615,337	$599,458	$1,671,519	$6,191,709	$4,152,651	0
Uncollectibles	$8,270,186	$7,070,741	$935,276	$264,169	0	0

*An electronic bill payment system.

Assumptions used in the analysis of customer information data include:

i. Customer count data was consolidated by customer class and not by location (network versus non-network) since none of the FERC accounts allocated on the basis of customer count required differentiation by location.
ii. The bills issued count is the total for each customer class and reflects the fact that Residential customers are billed every two months, while all other customer classes are billed monthly.
iii. The number of accounts can be less than or equal to the number of meters since some customers, particularly multifamily dwellings and larger businesses, have more than one service and meter but are billed for all meters under one account.
iv. In the case when customers have multiple meters on one account (some of which are billed under one class' rate schedule and some under another class), the larger class (in terms of maximum demand definition) is assigned the account.

Meter reading expenses were allocated using weighted meter counts, which are summarized in **Table 3.46**. Weighting factors were developed for the Residential, Small General Service, and Medium General Service customer classes based on an estimate of the amount of meter reading resources used for each class. Weighting factors considered whether the route was walk or drive, and the number of meter reads per year. Weighting factors have not changed since the 2007-2008 COSACAR because little has changed in the logistics of the meter reading activities since that time. Large and High Demand General Service meters are read electronically and the billing information is prepared by separate staff. The costs of the meter reading activities of these two customer classes are isolated and treated separately. Therefore, the weights for these two classes are assigned the value of 1.0.

Table 3.46: Weighted Meter Reading Counts

	Total	Residential	Small	Medium	Large	High Demand
Meter Count	406,274	360,010	42,993	3,120	140	11
Non-network		343,688	39,886	2,593	87	
Network		16,322	3,107	527	53	
Meter Reading Weightings						
Non-network		1.00	1.18	2.98	1.00	1.00
Network		1.78	1.70	2.13	1.00	
Weighted Meter Reading Counts	434,089	372,741	52,347	8,850	140	11
Non-network		343,688	47,065	7,727	87	
Network		29,054	5,282	1,123	53	

Table 3.47 summarizes the allocation factors used for different customer costs. Some factors allocate costs only over Residential, Small and Medium General Service classes (factor names with suffixes such as _R_S_M). Other factors allocate costs only over Large and High Demand General Service classes (factor names with suffixes such as _L_HD). Yet others allocate costs over all classes (factor names with the suffix _ALL).

Table 3.47: Customer Cost Allocation Factors

	Total	Residential	Small	Medium	Large	High Demand
METER READING						
MR_R_S_M	100%					
Non-network		79.20%	10.85%	1.78%		
Network		6.70%	1.22%	0.26%		
MR_L_HD	100%					
Non-network					57.62%	7.28%
Network					35.10%	
MR_ALL	100%					
Non-network		79.17%	10.84%	1.78%	0.02%	0.00%
Network		6.69%	1.22%	0.26%	0.01%	
METER COUNT						
MC_R_S_M	100%	88.65%	10.59%	0.77%		
MC_L_HD	100%				92.72%	7.28%
MC_ALL	100%	88.61%	10.58%	0.77%	0.03%	0.00%
Wgt. Avg. MC_ALL and MC_L_HD (2/3 to R, S,and M, and 1/3 to L and HD)	100%	59.10%	7.06%	0.51%	30.91%	2.43%
CUSTOMER COUNT						
C_R_S_M	100%	91.04%	8.24%	0.72%		
C_S_M	100%		92.00%	8.00%		
C_L_HD	100%				93.71%	6.29%
C_S_M_L_HD	100%		91.63%	7.96%	0.38%	0.03%
C_ALL	100%	91.01%	8.24%	0.72%	0.03%	0.00%
BILLS ISSUED						
BI_R_S_M	100%	88.96%	9.76%	1.28%		
BI_ALL	100%	88.90%	9.76%	1.28%	0.06%	0.00%
BI_L_HD	100%				93.79%	6.21%
kWh RELATED						
kWh	100%	33.19%	12.71%	26.14%	15.88%	12.09%
PAYMENT METHOD						
Cash or Check	100%	32.08%	13.75%	26.89%	17.42%	9.86%
Credit Card	100%	79.94%	11.71%	6.26%	2.09%	
Metavante	100%	48.63%	9.37%	18.93%	8.48%	14.59%
Average of Credit Card and Metavante	100%	64.29%	10.54%	12.59%	5.29%	7.29%
OTHER						
EU_BAD_DEBT	100%	85.50%	11.31%	3.19%		
EUC_BAD_DEBT	100%		77.98%	22.02%		

3.5.2. Customer Service Costs per Meter Computations

As shown in **Table 3.44**, total customer service expenditures in 2012 amounted to $40,067,150. City Light also received miscellaneous service revenues collected for commercial equipment rental, residential and commercial account change fees, and reconnect and field fees that totaled $2,505,542. These revenues offset the expenditures.

The results of 2012 customer service expenditure and revenue allocations among customer classes by FERC program codes are presented in **Tables 3.48-3.63**. The last line in each table shows marginal costs per meter associated with each FERC Program Code for each customer class. Below, we provide more details on derivations of the marginal costs in these tables.

Meter Reading Supervision and Meter Reading Expenses

Over 99% of the labor expenditures for FERC account 90201 originated from two Organization (Org.) Units, namely 472-Meter Reading and 473-Technical Metering. An allocation subtotal was computed for these expenditures. The remaining 0.7% of expenditures was allocated in proportion to this subtotal. **Table 3.48** summarizes these results.

Disconnect Service Non-Payment Expenses and Uncollectible Accounts

Disconnect service non-payment expenses in FERC account 90301 were directly related to the uncollectibles incurred by City Light. Costs associated with uncollectible accounts in FERC accounts 90401 and 90403 are also associated with uncollectible accounts. These three accounts are all allocated by EU_BAD_DEBT shares as seen in **Table 3.49**.

Credit Investigations and Records Expenses

Org. Units 463 and 464 contributed over 99.8% of the charges to FERC account 90311. Labor related expenditures were associated with serving Residential, Small and Medium General Service customers and were allocated accordingly. Non-labor expenditures were directly allocated to the Residential class because for both Org. Units at least 95% of non-labor costs (94% for Org. Unit 463 and over 95% for Org. Unit 464) were related to Residential customers.[6] **Table 3.50** has detailed results.

Collection-Light Department

The total dollars allocated in **Table 3.51** represented over 98% of all charges to FERC account 90321. The customer class totals from these allocated expenditures were computed and an overall allocation factor was developed. This overall factor was applied to the FERC account 90321 total of $4,699,063 to compute the final class allocations.

Collection-City Treasury, Banks, American Express

These fees were allocated to the customer classes in proportion to the average amount of payments made by the customer classes using credit. **Table 3.52** reports the results.

Customer Contracts and Orders

A single Org. Unit, 464-Customer Accounts, contributed 98% of the non-labor charges. The charges to this Org Unit were for the payment to Seattle Public Utilities to support the joint Call Center, which was the customer contact point for billing information services for the Residential, Small and Medium General Service customers. The sum of the expenditures allocated represented 99% of the total expenditures for this account. Ratios were developed from this

[6] Org. Unit 463 had non-labor charges of $242,000 for Project Share and $40,000 for Department of Information Technology (DoIT) activity billing charges. The DoIT activity billing was related to billing the small customers, 91% of which were Residential class. Project Share charges represented 82% of the total non-labor charges and were Residential class low-income assistance program-related. Org. Unit 464 had $1.6 million of non-labor charges, of which $1.44 million (91%) was for interfund payment for the Department of Neighborhoods Pay Center Bill Acceptance program and for the Human Services Department (HSD) for the Mayor's Office for Senior Citizens (MOSC). These charges were directly related to Residential customer count. The remaining percentage of non-labor charges was related to DoIT activity billing and postage and delivery. These expenditures were related to customer count, with the Residential class making up over 91%.

overall factor and applied to the FERC account 90351 total of $8,192,610 to compute the final class allocations. See **Table 3.53**.

Table 3.48: Meter Reading Supervision and Expenses: FERC 90101 and 90201

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90101		$195,163					
Non-network	MR_ALL		$154,519	$21,160	$3,474.	$39	$5
Network	MR_ALL		$13,062	$2,375	$505	$24	
FERC 90201							
Labor							
472 Meter Reading		$3,057,717					
Non-network	MR_R_SGS_MGS		$2,421,772	$331,644	$54,449		
Network	MR_R_SGS_MGS		$204,724	$37,219	$7,910		
473 Tech Metering		$126,861					
Non-network	MR_LGS_HDGS					$73,092	$9,242
Network	MR_LGS_HDGS					$44,527	
Non-Labor							
472 Meter Reading		$64,500					
Non-network	MR_ALL		$51,067	$6,993	$1,148	$13	$2
Network	MR_ALL		$4,317	$785	$167	$8	
Total Allocated		$3,249,077					
Non-network			$2,472,839	$338,637	$55,597	$73,105	$9,243
Network			$209,041	$38,003	$8,076	$44,535	
Overall Allocation Ratios							
Non-network			76.11%	10.42%	1.71%	2.25%	0.28%
Network			6.43%	1.17%	0.25%	1.37%	
Total FERC 90201		$3,273,234					
Non-network			$2,491,225	$341,155	$56,010	$73,648	$9,312
Network			$210,595	$38,286	$8,137	$44,866	
Total FERC 90101 and 90201		$3,468,397					
Non-network			$2,645,744	$362,315	$59,484	$73,688	$9,317
Network			$223,658	$40,661	$8,641	$44,890	
Meters							
Non-network			343,688	39,886	2,593	87	11
Network			16,322	3,107	527	53	
$2012/Meter							
Non-network			$7.70	$9.08	$22.94	$846.98	$846.98
Network			$13.70	$13.09	$16.40	$846.98	

Table 3.49: Disconnect Service Non-Payment: FERC 90301 and Uncollectible Accounts: FERC 90401 and 90403

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90301	EU_BAD_DEBT	$993,524	$849,431	$112,358	$31,735	$0	$0
FERC 90401	EU_BAD_DEBT	$6,472,982	$5,534,190	$732,030	$206,762	$0	$0
FERC 90403	EU_BAD_DEBT	$1,574,983	$1,346,559	$178,115	$50,309	$0	$0
Total		$9,041,489	$7,730,180	$1,022,503	$288,806	$0	$0
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$21.47	$23.78	$92.57	$0.00	$0.00

Table 3.50: Credit Investigations and Records: FERC 90311

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90311							
Labor							
463 Credit	C_R_S_M	$335,527	$305,478	$27,646	$2,402		
464 Customer Accounts	C_R_S_M	$271,272	$246,978	$22,352	$1,942		
Non-Labor							
463 Credit	DIRECT:RESID	$296,990	$296,990				
464 Customer Accounts	DIRECT:RESID	$1,589,174	$1,589,174				
Total Allocated		$2,492,963	$2,438,620	$49,998	$4,345		
Overall Allocation Ratios			97.82%	2.01%	0.17%		
Total FERC 90311		$2,497,730	$2,443,283	$50,093	$4,353		
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$6.79	$1.17	$1.40		

Table 3.51: Collection-Light Department: FERC 90321

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90321							
Labor							
341 North Customer Eng	C_R_S_M	$87,174	$79,367	$7,183	$624	$0	$0
352 South Customer Eng	C_R_S_M	$87,960	$80,083	$7,248	$630	$0	$0
430 CC Director's Office	C_R_S_M	$10,858	$9,886	$895	$78	$0	$0
431 Account Executives	C_L_HD	$1,701	$0	$0	$0	$1,594	$107
463 Credit	C_R_S_M	$1,471,807	$1,339,997	$121,271	$10,539	$0	$0
464 Customer Accounts	C_R_S_M	$194,810	$177,364	$16,052	$1,395	$0	$0
473 Technical Metering	C_L_HD	$6,118	$0	$0	$0	$5,733	$385
522 IT Operations	C_ALL	$157,601	$143,435	$12,981	$1,128	$54	$4
523 IT Applic Dev Serv	C_ALL	$1,036,739	$943,547	$85,392	$7,421	$355	$24
000 Financial Statement	C_ALL	$14,521	$13,216	$1,196	$104	$5	$0
Non-Labor							
430 CC Director's Office	C_ALL	$0	$0	$0	$0	$0	$0
523 IT Applic Dev Serv	C_ALL	$1,556,589	$1,416,669	$128,210	$11,142	$533	$36
831 General Expenses	C_ALL	$0	$0	$0	$0	$0	$0
Total Allocated		**$4,625,880**	**$4,203,564**	**$380,427**	**$33,060**	**$8,274**	**$556**
Overall Allocation Ratios			90.87%	8.22%	0.71%	0.18%	0.01%
Total FERC 90321		$4,699,063	$4,270,066	$386,445	$33,583	$8,405	$565
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$11.86	$8.99	$10.76	$60.03	$51.32

Table 3.52: Collection-City Treasury, Banks, American Express: FERC 90341

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90341		$2,003,182					
	Average of Credit Card and Metavante		$1,287,790	$211,148	$252,245	$105,870	$146,129
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$3.58	$4.91	$80.85	$756.22	$13,284.47

Table 3.53: Customer Contracts and Orders: FERC 90351

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90351							
Labor							
341 North Customer Eng	C_R_S_M	$599,083	$545,431	$49,362	$4,290	$0	$0
352 South Customer Eng	C_R_S_M	$846,215	$770,431	$69,725	$6,059	$0	$0
430 CC Director's Office	C_ALL	$1,021	$929	$84	$7	$0	$0
463 Credit	C_R_S_M	$287,549	$261,797	$23,693	$2,059	$0	$0
464 Customer Accounts	C_R_S_M	$1,862,680	$1,695,865	$153,477	$13,337	$0	$0
Non-Labor							
341 North Customer Eng	C_R_S_M	$26,191	$23,845	$2,158	$188	$0	$0
352 South Customer Eng	C_R_S_M	$32,761	$29,827	$2,699	$235	$0	$0
430 CC Director's Office	C_ALL	$0	$0	$0	$0	$0	$0
464 Customer Accounts	C_R_S_M	$4,459,180	$4,059,832	$367,419	$31,929	$0	$0
Total Allocated		$8,114,680	$7,387,958	$668,617	$58,104	$0	$0
Overall Allocation Ratios			91.04%	8.24%	0.72%	0.00%	0.00%
Total FERC 90351		$8,192,610	$7,458,909	$675,039	$58,662	$0	$0
Meters							
Total Service Territory			360,010	42,993	3,120	140	11
$2012/Meter							
Total Service Territory			$20.72	$15.70	$18.80	$0.00	$0.00

Bill Revenue Accounting and Mailing

Expenditures from seven Org. Units contributed over 97% of the charges to the FERC account 90361. The non-labor expenditures were postage costs and supplies for mailing utility bills. Ratios were developed from this overall factor and applied to the total of $3,650,268 to compute the final class allocations. Results are in **Table 3.54**.

Miscellaneous Customer Accounting Expenses

Expenditures from six Org. Units contributed 99.3% of the charges to FERC account 90501. Ratios were developed from this overall factor and applied to the total of $845,120 to compute the final class allocations. See **Table 3.55**.

Supervision Expenses

FERC account 90701 costs were directly assigned to the Residential class as seen in **Table 3.56**. (FERC account 90711-Commercial and Industrial Supervision, which was included in the last cost of service study, showed expense of $0 in 2012 and was, therefore, excluded from this study.)

Customer Assistance Expenses

Costs for FERC account 90801, Customer Assistance Expenses–Residential, were directly assigned to the Residential class and costs for FERC account 90811, Customer Assistance – Commercial and Industrial, were allocated among other customer classes as indicated in **Table 3.57**.

Table 3.54: Bill Revenue Accounting and Mailings: FERC 90361

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90361							
Labor							
341 North Customer Eng	BI_R_S_M	$65,986	$58,699	$6,444	$843	$0	$0
352 South Customer Eng	BI_R_S_M	$13,575	$12,076	$1,326	$173	$0	$0
431 Account Executives	BI_L_HD	$7,531	$0	$0	$0	$7,063	$468
464 Customer Accounts	BI_R_S_M	$1,091,099	$970,615	$106,546	$13,939	$0	$0
543 General Accounting	BI_ALL	$273,029	$242,722	$26,644	$3,486	$166	$11
Non-Labor							
463 Credit	BI_ALL	$161,297	$143,393	$15,740	$2,059	$98	$7
464 Customer Accounts	BI_ALL	$1,495,096	$1,329,135	$145,901	$19,088	$911	$60
580 Office Supplies	BI_ALL	$441,257	$392,276	$43,061	$5,633	$269	$18
Total Allocated		$3,548,870	$3,148,916	$345,660	$45,221	$8,508	$564
Overall Allocation Ratios			88.73%	9.74%	1.27%	0.24%	0.02%
Total FERC 90361		$3,650,268	$3,238,887	$355,537	$46,514	$8,751	$580
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$9.00	$8.27	$14.91	$62.51	$52.71

Table 3.55: Miscellaneous Customer Account Expenses: FERC 90501

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90501							
Labor							
430 CC Director's Office	C_ALL	$401,812	$365,694	$33,096	$2,876	$137	$9
431 Account Executives	C_L_HD	$7,244	$0	$0	$0	$6,788	$456
463 Credit	C_R_S_M	$39,330	$35,808	$3,241	$282	$0	$0
464 Customer Accounts	C_R_S_M	$84,828	$77,231	$6,990	$607	$0	$0
472 Meter Reading	C_R_S_M	$5,150	$4,688	$424	$37	$0	$0
473 Technical Metering	C_L_HD	$221,008	$0	$0	$0	$207,098	$13,910
Non-Labor							
430 CC Director's Office	C_ALL	$75,780	$68,969	$6,242	$542	$26	$2
473 Technical Metering	C_L_HD	$3,989	$0	$0	$0	$3,738	$251
Total Allocated		$839,141	$552,390	$49,992	$4,344	$217,788	$14,628
Overall Allocation Ratios			65.83%	5.96%	0.52%	25.95%	1.74%
Total FERC 90501		$845,120	$556,326	$50,348	$4,375	$219,339	$14,732
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$1.55	$1.17	$1.40	$1,566.71	$1,339.25

Table 3.56: Supervision-Residential: FERC 90701

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90701	DIRECT: RESID	$65,464	$65,464	$0	$0	$0	$0
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$0.18	$0.00	$0.00	$0.00	$0.00

Table 3.57: Customer Assistance Expenses: FERC 90801 and FERC 90811

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 90801		$2,869,381					
Total Service Territory	DIRECT: RESID		$2,869,381	$0	$0	$0	$0
FERC 90811							
Labor							
341 North Customer Eng	C_S_M	$220,738	$0	$203,090	$17,649	$0	$0
352 South Customer Eng	C_S_M	$180,906	$0	$166,442	$14,464	$0	$0
431 Account Executives	C_L_HD	$339,311	$0	$0	$0	$317,956	$21,355
000 Financial Statement	C_S_M_L_HD	$815,810	$0	$747,534	$64,962	$3,106	$209
Non-Labor							
341 North Customer Engineering	C_S_M	$4,896	$0	$4,505	$391	$0	$0
352 South Customer Engineering	C_S_M	$1,823	$0	$1,678	$146	$0	$0
Total Allocated		$1,563,485	$0	$1,123,248	$97,612	$321,061	$21,564
Overall Allocation Ratios			0.00%	71.84%	6.24%	20.53%	1.38%
Total FERC 90811		$1,695,637	$0	$1,218,189	$105,862	$348,199	$23,386
Total FERC 90801 & 90811		$4,565,018	$2,869,381	$1,218,189	$105,862	$348,199	$23,386
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$7.97	$28.33	$33.93	$2,487.13	$2,126.04

Miscellaneous Customer Service and Information Expenses

Miscellaneous activities charged to FERC account 91001 include support for phone notifications of schools, hospitals, and customers on life support regarding outages; suburban cities support; and general power quality metering issues. The allocated Org. Unit charges represent over 99% of the total charges to the account. Ratios were developed from this overall factor and applied to the total of $776,543 to compute the final class allocations. See **Table 3.58**.

General Advertising Expenses

General advertising expense, FERC account 93010, is allocated as indicated in **Table 3.59**. These costs are allocated based on the customer count allocation factors.

Miscellaneous Service Revenues

These revenues were allocated to the customer classes from which the revenues were received, with the reconnection and field charges allocated on the basis of EUC_BAD_DEBT. Results are in **Table 3.60**.

Table 3.58: Miscellaneous Customer Service and Information Expenses: FERC 91001

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 91001							
Labor							
431 Account Executives	C_ALL	$727,411	$662,025	$59,914	$5,207	$249	$17
473 Technical Metering	C_ALL	$10,704	$9,742	$882	$77	$4	$0
Non-Labor							
430 CC Director's Office	C_R_S_M	$8,000	$7,284	$659	$57	$0	$0
431 Account Executives	C_ALL	$23,705	$21,574	$1,952	$170	$8	$1
Total Allocated		$769,820	$700,625	$63,407	$5,510	$261	$18
Overall Allocation Ratios			91.01%	8.24%	0.72%	0.03%	0.002%
Total FERC 91001		$776,543	$706,743	$63,961	$5,558	$263	$18
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$1.96	$1.49	$1.78	$1.88	$1.61

Table 3.59: General Advertising: FERC 93010

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 93010		$262,268					
	C_ALL		$238,693	$21,602	$1,877	$90	$6
Meters			360,010	42,993	3,120	140	11
$2012/Meter			$0.66	$0.50	$0.60	$0.64	$0.55

Table 3.60: Miscellaneous Service Revenues: FERC 45110, 45130, 45131, and 45150

	Allocation Factor	Total	Residential	Small	Medium	Large	High Demand
FERC 45110	C_S_M_L_HD	-$159,690	$0	-$146,325	-$12,716	-$608	-$41
FERC 45130	DIRECT: RESID	-$1,234,468	-$1,234,468	$0	$0	$0	$0
FERC 45131	C_S_M_L_HD	-$9,022	$0	-$8,267	-$718	-$34	-$2
FERC 45150	EUC_BAD_DEBT	-$1,102,362	$0	-$859,575	-$242,787	$0	$0
Total 451XX		-$2,505,542	-$1,234,468	-$1,014,167	-$256,221	-$642	-$43
Meters			360,010	42,993	3,120	140	11
$2012/Meter			-$3.43	-$23.59	-$82.12	-$4.59	-$3.92

Tables 3.61 and **3.62** show the derivation of the 2012 marginal customer costs per meter by non-network and network customer classes, respectively. The tables sum individual per meter costs by FERC account for each customer class and then adjust them for customer service revenues per meter, derived in **Table 3.60**.

Table 3.61: 2012 Non-network Customer Costs per Meter by Customer Class

FERC #	Residential	Small	Medium	Large	High Demand
90101 & 90201	$7.70	$9.08	$22.94	$846.98	$846.98
90301 & 90401 & 90403	$21.47	$23.78	$92.57	$0.00	$0.00
90311	$6.79	$1.17	$1.40	$0.00	$0.00
90321	$11.86	$8.99	$10.76	$60.03	$51.32
90341	$3.58	$4.91	$80.85	$756.22	$13,284.47
90351	$20.72	$15.70	$18.80	$0.00	$0.00
90361	$9.00	$8.27	$14.91	$62.51	$52.71
90501	$1.55	$1.17	$1.40	$1,566.71	$1,339.25
90701 & 90711 & 90801	$0.18	$0.00	$0.00	$0.00	$0.00
90811	$7.97	$28.33	$33.93	$2,487.13	$2,126.04
91001	$1.96	$1.49	$1.78	$1.88	$1.61
93010	$0.66	$0.50	$0.60	$0.64	$0.55
Subtotal	**$93.43**	**$103.40**	**$279.94**	**$5,782.10**	**$17,702.94**
451XX	-$3.43	-$23.59	-$82.12	-$4.59	-$3.92
$2012 Cost per Meter	**$90.00**	**$79.81**	**$197.82**	**$5,777.52**	**$17,699.02**

Table 3.62: 2012 Network Customer Costs per Meter by Customer Class

FERC #	Residential	Small	Medium	Large
90101 & 90201	$13.70	$13.09	$16.40	$846.98
90301 & 90401 & 90403	$21.47	$23.78	$92.57	$0.00
90311	$6.79	$1.17	$1.40	$0.00
90321	$11.86	$8.99	$10.76	$60.03
90341	$3.58	$4.91	$80.85	$756.22
90351	$20.72	$15.70	$18.80	$0.00
90361	$9.00	$8.27	$14.91	$62.51
90501	$1.55	$1.17	$1.40	$1,566.71
90701 &90711 & 90801	$0.18	$0.00	$0.00	$0.00
90811	$7.97	$28.33	$33.93	$2,487.13
91001	$1.96	$1.49	$1.78	$1.88
93010	$0.66	$0.50	$0.60	$0.64
Subtotal	**$99.44**	**$107.40**	**$273.40**	**$5,782.10**
451XX	-$3.43	-$23.59	-$82.12	-$4.59
$2012 Cost per Meter	**$96.01**	**$83.81**	**$191.27**	**$5,777.52**

3.5.3. Total Customer Costs

Table 3.63 shows total customer service costs by customer class in 2015 and 2016, which were derived by inflating 2012 per meter costs and then multiplying them by projected number of meters.

Table 3.63: 2015 and 2016 Total Customer Costs by Customer Class

		Residential	Small	Medium	Large	High Demand
Non-network $2012 Costs per Meter		$90.00	$79.81	$197.82	$5,777.52	$17,699.02
Network $2012 Costs per Meter		$96.01	$83.81	$191.27	$5,777.52	
2015 Customer Costs					**$2015 inflation adjustment =**	**1.05786**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2015 Meters	399,730	356,895	40,156	2,572	95	12
$2015 Total Costs	$38,714,831	$33,980,854	$3,390,250	$538,222	$580,622	$224,882
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2015 Meters	20,294	16,450	3,244	541	59	
$2015 Total Costs	$2,428,463	$1,670,782	$287,618	$109,466	$360,597	
Service Territory	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
$2015 Total Cost	$41,143,293	$35,651,636	$3,677,868	$647,689	$941,218	$224,882
2016 Customer Costs					**$2016 inflation adjustment =**	**1.08372**
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
2016 Meters	399,730	356,895	40,156	2,572	95	12
$2016 Total Costs	$39,661,139	$34,811,450	$3,473,118	$551,378	$594,814	$230,379
Downtown Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	
2016 Meters	20,294	16,450	3,244	541	59	
$2016 Total Costs	$2,487,822	$1,711,621	$294,649	$112,142	$369,411	
Service Territory	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
$2016 Total Cost	$42,148,960	$36,523,070	$3,767,767	$663,520	$964,225	$230,379

3.6. Summary of Allocation Factors

Tables 3.67 and **3.68** summarize 2015 and 2016 Total Energy, Distribution and Customer Costs by customer class derived in Sections 3.3-3.5 using the marginal cost approach. **Tables 3.69** and **3.70** present allocation factors that were calculated using information about total costs in **Tables 3.67** and **3.68**. These factors were used to allocate functionalized revenue requirements by customer class for 2015 and 2016.

Table 3.67: 2015 Total Energy, Distribution and Customer Costs by Customer Class

Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	$445,674,331	$148,131,667	$56,782,302	$116,212,385	$70,285,136	$51,239,470	$3,023,373
Distribution							
ISA Transmission	$48,815,299	$19,332,042	$6,108,189	$11,977,645	$6,963,551	$4,198,001	$235,872
Stations	$33,284,536	$13,107,177	$4,160,080	$8,203,778	$4,811,148	$2,842,635	$159,718
Wires & Rel.	$254,558,943	$100,854,287	$29,953,798	$62,327,544	$45,412,569	$15,167,190	$843,555
Transformers	$16,916,662	$3,711,529	$2,386,893	$7,317,840	$3,005,798	$419,798	$74,803
Meters	$5,836,707	$3,921,880	$936,190	$234,296	$689,132	$55,208	
Streetlights							
Customer Costs	$41,143,293	$35,651,636	$3,677,868	$647,689	$941,218	$224,882	
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$380,002,605	$143,783,254	$49,973,543	$89,438,585	$42,544,382	$51,239,470	$3,023,373
Distribution							
ISA Transmission	$42,001,641	$18,837,444	$5,396,985	$9,212,487	$4,120,852	$4,198,001	$235,872
Stations	$28,440,993	$12,755,588	$3,654,514	$6,238,144	$2,790,394	$2,842,635	$159,718
Wires & Rel.	$181,033,029	$94,152,477	$22,238,736	$33,586,242	$15,044,828	$15,167,190	$843,555
Transformers	$8,940,033	$3,159,364	$1,524,600	$3,077,268	$684,199	$419,798	$74,803
Meters	$5,233,323	$3,737,712	$821,749	$193,578	$425,075	$55,208	
Streetlights							
Customer Costs	$38,714,831	$33,980,854	$3,390,250	$538,222	$580,622	$224,882	
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$65,671,726	$4,348,414	$6,808,759	$26,773,800	$27,740,754		
Distribution							
ISA Transmission	$6,813,659	$494,598	$711,204	$2,765,158	$2,842,698		
Stations	$4,843,543	$351,589	$505,565	$1,965,634	$2,020,754		
Wires & Rel.	$73,525,914	$6,701,810	$7,715,062	$28,741,301	$30,367,741		
Transformers	$7,976,629	$552,165	$862,292	$4,240,572	$2,321,599		
Meters	$603,384	$184,168	$114,441	$40,718	$264,057		
Streetlights							
Customer Costs	$2,428,463	$1,670,782	$287,618	$109,466	$360,597		

Table 3.68: 2016 Total Energy, Distribution and Customer Costs by Customer Class

Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	$470,750,759	$155,223,407	$60,160,100	$123,336,112	$74,532,916	$54,542,327	$2,955,898
Distribution							
ISA Transmission	$50,008,494	$19,763,976	$6,326,716	$12,301,144	$7,119,569	$4,280,488	$216,601
Stations	$34,099,147	$13,402,567	$4,309,723	$8,423,402	$4,918,295	$2,898,490	$146,669
Wires & Rel.	$262,622,280	$104,964,180	$31,374,006	$63,653,883	$46,378,139	$15,476,885	$775,187
Transformers	$17,389,534	$3,790,640	$2,461,049	$7,544,117	$3,094,312	$430,224	$69,190
Meters	$5,979,374	$4,017,743	$959,074	$240,023	$705,976	$56,558	
Streetlights							
Customer Costs	$42,148,960	$36,523,070	$3,767,767	$663,520	$964,225	$230,379	
Non-network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$401,266,720	$150,669,987	$52,962,870	$94,984,356	$45,151,281	$54,542,327	$2,955,898
Distribution							
ISA Transmission	$42,997,577	$19,183,061	$5,565,979	$9,519,070	$4,232,379	$4,280,488	$216,601
Stations	$29,115,382	$12,989,619	$3,768,947	$6,445,743	$2,865,913	$2,898,490	$146,669
Wires & Rel.	$187,299,169	$97,356,920	$23,172,226	$34,860,410	$15,657,541	$15,476,885	$775,187
Transformers	$9,181,246	$3,226,909	$1,573,073	$3,178,207	$703,642	$430,224	$69,190
Meters	$5,361,242	$3,829,073	$841,835	$198,310	$435,465	$56,558	
Streetlights							
Customer Costs	$39,661,139	$34,811,450	$3,473,118	$551,378	$594,814	$230,379	
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	$69,484,039	$4,553,419	$7,197,230	$28,351,756	$29,381,635		
Distribution							
ISA Transmission	$7,010,917	$580,915	$760,737	$2,782,074	$2,887,190		
Stations	$4,983,765	$412,948	$540,776	$1,977,659	$2,052,382		
Wires & Rel.	$75,323,111	$7,607,260	$8,201,781	$28,793,472	$30,720,598		
Transformers	$8,208,288	$563,732	$887,976	$4,365,910	$2,390,670		
Meters	$618,132	$188,669	$117,238	$41,713	$270,511		
Streetlights							
Customer Costs	$2,487,822	$1,711,621	$294,649	$112,142	$369,411		

Table 3.69: 2015 Functionalized Revenue Requirement Allocation Factors

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	85.26%	32.26%	11.21%	20.07%	9.55%	11.50%	0.68%
Distribution							
In Service Area Transmission	86.04%	38.59%	11.06%	18.87%	8.44%	8.60%	0.48%
Stations	85.45%	38.32%	10.98%	18.74%	8.38%	8.54%	0.48%
Wires & Related Equipment	100.00%	52.01%	12.28%	18.55%	8.31%	8.38%	0.47%
Transformers	100.00%	35.34%	17.05%	34.42%	7.65%	4.70%	0.84%
Meters	89.66%	64.04%	14.08%	3.32%	7.28%	0.95%	
Streetlights							100.00%
Customer Costs	94.10%	82.59%	8.24%	1.31%	1.41%	0.55%	
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	14.74%	0.98%	1.53%	6.01%	6.22%		
Distribution							
In Service Area Transmission	13.96%	1.01%	1.46%	5.66%	5.82%		
Stations	14.55%	1.06%	1.52%	5.91%	6.07%		
Wires & Related Equipment	100.00%	9.11%	10.49%	39.09%	41.30%		
Transformers	100.00%	6.92%	10.81%	53.16%	29.11%		
Meters	10.34%	3.16%	1.96%	0.70%	4.52%		
Streetlights							
Customer Costs	5.90%	4.06%	0.70%	0.27%	0.88%		

Table 3.70: 2016 Functionalized Revenue Requirement Allocation Factors

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Energy	85.24%	32.01%	11.25%	20.18%	9.59%	11.59%	0.63%
Distribution							
In Service Area Transmission	85.98%	38.36%	11.13%	19.03%	8.46%	8.56%	0.43%
Stations	85.38%	38.09%	11.05%	18.90%	8.40%	8.50%	0.43%
Wires & Related Equipment	100.00%	51.98%	12.37%	18.61%	8.36%	8.26%	0.41%
Transformers	100.00%	35.15%	17.13%	34.62%	7.66%	4.69%	0.75%
Meters	89.66%	64.04%	14.08%	3.32%	7.28%	0.95%	
Streetlights							100.00%
Customer Costs	94.10%	82.59%	8.24%	1.31%	1.41%	0.55%	0.00%
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Energy	14.76%	0.97%	1.53%	6.02%	6.24%		
Distribution							
In Service Area Transmission	14.02%	1.16%	1.52%	5.56%	5.77%		
Stations	14.62%	1.21%	1.59%	5.80%	6.02%		
Wires & Related Equipment	100.00%	10.10%	10.89%	38.23%	40.79%		
Transformers	100.00%	6.87%	10.82%	53.19%	29.13%		
Meters	10.34%	3.16%	1.96%	0.70%	4.52%		
Streetlights							
Customer Costs	5.90%	4.06%	0.70%	0.27%	0.88%		

Table 3.71 shows derivations of the allocation factors for the UDP. Factors were created by first summing total energy, distribution and customer costs by customer class and then dividing that sum by total energy, distribution and customer costs for the total service territory.

Table 3.71: 2015 and 2016 UDP Expense Allocation Factors

2015	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy, Distribution and Customer Service Costs							
Service Territory	$846,229,772	$324,710,218	$104,005,320	$206,921,177	$132,108,552	$74,147,184	$4,337,321
Non-network	$684,366,455	$310,406,693	$87,000,378	$142,284,527	$66,190,352	$74,147,184	$4,337,321
Network	$161,863,317	$14,303,525	$17,004,942	$64,636,650	$65,918,200		
Allocation Factors							
Non-network	80.87%	36.68%	10.28%	16.81%	7.82%	8.76%	0.51%
Network	19.13%	1.69%	2.01%	7.64%	7.79%		
2016	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy, Distribution and Customer Service Costs							
Service Territory	$882,998,548	$337,685,584	$109,358,435	$216,162,201	$137,713,433	$77,915,351	$4,163,545
Non-network	$714,882,473	$322,067,019	$91,358,048	$149,737,475	$69,641,035	$77,915,351	$4,163,545
Network	$168,116,075	$15,618,564	$18,000,387	$66,424,726	$68,072,397		
Allocation Factors							
Non-network	80.96%	36.47%	10.35%	16.96%	7.89%	8.82%	0.47%
Network	19.04%	1.77%	2.04%	7.52%	7.71%		

4. Cost Allocation

4.1. Initial Allocation

Tables 4.1 and **4.2** present the initial allocation of the functionalized revenue requirements by customer class for 2015 and 2016, respectively. The allocation factors shown in **Tables 3.69-3.71** for non-network and network customer classes are multiplied by the total service territory revenue requirements for each expense category from **Table 2.1,** except for Wires and Related Equipment, and Transformers. The total network revenue requirements for these two categories are first multiplied by 85% (the percent of total network load that is in the downtown network), and those results are then allocated to downtown network customer classes using the network allocation factors. The remaining revenue requirements for these two categories are then allocated to the non-network classes using the non-network allocation factors.

Tables 4.3 and **4.4** show forecasted 2015 and 2016 total energy consumption by non-network customer class and jurisdiction (i.e. Seattle, Shoreline, Tukwila and Other Suburbs). **Tables 4.5** and **4.6** show percentages of non-network energy consumption by customer class for each jurisdiction as a percent of total non-network energy consumption by customer class. These percentages are used to allocate 2015 and 2016 non-network revenue requirements from **Tables 4.1** and **4.2** among customers in Seattle, Shoreline, Tukwila and Other Suburbs. **Tables 4.7** and **4.8** summarize these results.

Table 4.1: 2015 Initial Allocation of Functionalized Revenue Requirements

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	**$442,478,557**	**$167,422,554**	**$58,189,656**	**$104,143,117**	**$49,539,073**	**$59,663,714**	**$3,520,443**
Production	$117,681,106	$44,527,517	$15,476,056	$27,697,788	$13,175,357	$15,868,095	$936,293
Purchased Power	$239,605,755	$90,660,681	$31,510,175	$56,394,349	$26,825,813	$32,308,389	$1,906,349
Conservation	$37,265,189	$14,100,193	$4,900,686	$8,770,850	$4,172,141	$5,024,830	$296,489
Transmission-Long Distance	$47,926,506	$18,134,162	$6,302,739	$11,280,130	$5,365,762	$6,462,400	$381,312
Total Retail Services	**$267,460,631**	**$150,425,314**	**$31,014,160**	**$39,953,619**	**$18,097,021**	**$16,445,061**	**$11,525,456**
Distribution	$197,036,998	$93,591,001	$24,382,935	$36,697,652	$16,081,746	$14,832,591	$11,451,074
In Service Area Transmission	$12,959,138	$5,812,083	$1,665,179	$2,842,410	$1,271,443	$1,295,246	$72,776
Stations	$34,429,346	$15,441,322	$4,423,986	$7,551,607	$3,377,922	$3,441,161	$193,348
Wires & Related Equipment	$110,037,220	$57,228,656	$13,517,361	$20,414,710	$9,144,691	$9,219,066	$512,737
Transformers	$15,668,220	$5,537,073	$2,672,000	$5,393,191	$1,199,121	$735,735	$131,099
Meters	$13,401,961	$9,571,867	$2,104,409	$495,733	$1,088,569	$141,383	$0
Streetlights	$10,541,113						$10,541,113
Customer Costs	$58,687,208	$51,511,047	$5,139,227	$815,883	$880,155	$340,896	
Utility Discount Program	$11,736,425	$5,323,266	$1,491,998	$2,440,084	$1,135,120	$1,271,574	$74,382
Total	**$709,939,187**	**$317,847,868**	**$89,203,816**	**$144,096,736**	**$67,636,094**	**$76,108,775**	**$15,045,899**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$76,468,767**	**$5,063,333**	**$7,928,182**	**$31,175,661**	**$32,301,591**		
Production	$20,337,549	$1,346,638	$2,108,571	$8,291,444	$8,590,895		
Purchased Power	$41,408,463	$2,741,836	$4,293,175	$16,881,875	$17,491,575		
Conservation	$6,440,138	$426,430	$667,705	$2,625,589	$2,720,414		
Transmission-Long Distance	$8,282,618	$548,429	$858,731	$3,376,752	$3,498,706		
Total Retail Services	**$64,005,306**	**$7,947,216**	**$6,930,193**	**$25,052,732**	**$24,075,165**		
Distribution	$57,548,190	$5,169,208	$6,202,574	$23,778,319	$22,398,090		
In Service Area Transmission	$2,102,278	$152,603	$219,434	$853,159	$877,083		
Stations	$5,863,368	$425,617	$612,014	$2,379,505	$2,446,231		
Wires & Related Equipment	$36,215,871	$3,301,039	$3,800,125	$14,156,795	$14,957,913		
Transformers	$11,821,474	$818,316	$1,277,929	$6,284,587	$3,440,642		
Meters	$1,545,199	$471,634	$293,071	$104,273	$676,221		
Streetlights	$0						
Customer Costs	$3,681,268	$2,532,712	$435,996	$165,938	$546,623		
Utility Discount Program	$2,775,847	$245,296	$291,623	$1,108,475	$1,130,453		
Total	**$140,474,073**	**$13,010,549**	**$14,858,375**	**$56,228,393**	**$56,376,756**		
Service Territory	**$850,413,261**	**$330,858,416**	**$104,062,191**	**$200,325,129**	**$124,012,850**	**$76,108,775**	**$15,045,899**

Table 4.2: 2016 Initial Allocation of Functionalized Revenue Requirements

Non-network	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	**$466,843,619**	**$175,293,187**	**$61,618,312**	**$110,507,147**	**$52,530,117**	**$63,455,891**	**$3,438,965**
Production	$125,009,351	$46,939,246	$16,499,883	$29,591,123	$14,066,286	$16,991,942	$920,871
Purchased Power	$249,230,622	$93,582,579	$32,895,749	$58,995,698	$28,043,895	$33,876,764	$1,835,937
Conservation	$40,696,241	$15,280,864	$5,371,464	$9,633,259	$4,579,217	$5,531,652	$299,785
Transmission-Long Distance	$51,907,404	$19,490,497	$6,851,216	$12,287,068	$5,840,718	$7,055,533	$382,372
Total Retail Services	**$275,611,463**	**$154,838,020**	**$32,051,182**	**$41,133,989**	**$18,673,564**	**$16,747,272**	**$12,167,437**
Distribution	$201,253,174	$95,253,665	$25,004,679	$37,499,485	$16,462,268	$14,943,097	$12,089,980
In Service Area Transmission	$13,625,299	$6,078,830	$1,763,777	$3,016,453	$1,341,178	$1,356,424	$68,638
Stations	$35,108,894	$15,663,582	$4,544,799	$7,772,624	$3,455,872	$3,495,155	$176,861
Wires & Related Equipment	$111,385,128	$57,897,283	$13,780,314	$20,731,172	$9,311,399	$9,203,964	$460,997
Transformers	$15,765,869	$5,541,189	$2,701,253	$5,457,560	$1,208,282	$738,773	$118,812
Meters	$14,103,311	$10,072,781	$2,214,537	$521,675	$1,145,536	$148,781	
Streetlights	$11,264,673						$11,264,673
Customer Costs	$61,058,935	$53,592,763	$5,346,919	$848,855	$915,725	$354,672	
Utility Discount Program	$13,299,355	$5,991,591	$1,699,584	$2,785,649	$1,295,571	$1,449,502	$77,457
Total	**$742,455,082**	**$330,131,207**	**$93,669,494**	**$151,641,137**	**$71,203,680**	**$80,203,163**	**$15,606,402**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$80,839,449**	**$5,297,560**	**$8,373,435**	**$32,985,133**	**$34,183,320**		
Production	$21,646,836	$1,418,558	$2,242,202	$8,832,615	$9,153,461		
Purchased Power	$43,157,206	$2,828,173	$4,470,269	$17,609,548	$18,249,216		
Conservation	$7,047,032	$461,805	$729,939	$2,875,419	$2,979,869		
Transmission-Long Distance	$8,988,376	$589,025	$931,025	$3,667,551	$3,800,775		
Total Retail Services	**$65,185,503**	**$8,602,112**	**$7,248,550**	**$25,066,890**	**$24,267,951**		
Distribution	$58,227,907	$5,676,485	$6,460,063	$23,658,510	$22,432,849		
In Service Area Transmission	$2,221,656	$184,083	$241,066	$881,598	$914,908		
Stations	$6,009,692	$497,955	$652,097	$2,384,768	$2,474,873		
Wires & Related Equipment	$36,393,750	$3,675,588	$3,962,842	$13,912,097	$14,843,223		
Transformers	$11,976,747	$822,543	$1,295,650	$6,370,317	$3,488,236		
Meters	$1,626,062	$496,315	$308,408	$109,730	$711,609		
Streetlights							
Customer Costs	$3,830,040	$2,635,066	$453,616	$172,644	$568,713		
Utility Discount Program	$3,127,557	$290,561	$334,871	$1,235,736	$1,266,389		
Total	**$146,024,952**	**$13,899,672**	**$15,621,985**	**$58,052,024**	**$58,451,271**		
Service Territory	**$888,480,034**	**$344,030,879**	**$109,291,479**	**$209,693,160**	**$129,654,951**	**$80,203,163**	**$15,606,402**

Table 4.3: 2015 Total Non-network Energy Consumption by Jurisdiction

2015	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Non-network	8,156,323	3,064,864	1,062,355	1,916,508	919,789	1,124,315	68,493
City of Seattle	6,617,469	2,365,969	896,927	1,623,473	766,322	896,284	68,493
Shoreline	381,174	232,017	43,862	88,733	16,562	0	0
Tukwila	534,453	58,718	29,361	106,280	112,063	228,030	0
Other Suburbs	623,228	408,160	92,205	98,022	24,842	0	0

Table 4.4: 2016 Total Non-network Energy Consumption by Jurisdiction

2016	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Non-network	8,190,141	3,064,069	1,072,909	1,937,438	925,887	1,127,827	62,011
City of Seattle	6,645,073	2,365,285	905,750	1,640,986	771,570	899,471	62,011
Shoreline	383,440	231,800	44,316	90,626	16,698	0	0
Tukwila	536,553	58,714	29,740	106,970	112,773	228,356	0
Other Suburbs	625,075	408,270	93,103	98,857	24,846	0	0

Table 4.5: 2015 Percentages of Non-network Energy Consumption by Jurisdiction

2015	Total	Residential	Small	Medium	Large	High Demand	Lights
City of Seattle	81.13%	77.20%	84.43%	84.71%	83.32%	79.72%	100.00%
Shoreline	4.67%	7.57%	4.13%	4.63%	1.80%		
Tukwila	6.55%	1.92%	2.76%	5.55%	12.18%	20.28%	
Other Suburbs	7.64%	13.32%	8.68%	5.11%	2.70%		

Table 4.6: 2016 Percentages of Non-network Energy Consumption by Jurisdiction

2016	Total	Residential	Small	Medium	Large	High Demand	Lights
City of Seattle	81.14%	77.19%	84.42%	84.70%	83.33%	79.75%	100.00%
Shoreline	4.68%	7.57%	4.13%	4.68%	1.80%		
Tukwila	6.55%	1.92%	2.77%	5.52%	12.18%	20.25%	
Other Suburbs	7.63%	13.32%	8.68%	5.10%	2.68%		

Table 4.7: 2015 Non-network Revenue Requirements Allocated by Jurisdiction

City of Seattle	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	**$358,949,303**	**$129,244,436**	**$49,128,471**	**$88,219,577**	**$41,273,494**	**$47,562,882**	**$3,520,443**
Production	$95,465,759	$34,373,707	$13,066,154	$23,462,781	$10,977,053	$12,649,771	$936,293
Purchased Power	$194,373,982	$69,986,919	$26,603,469	$47,771,622	$22,349,934	$25,755,689	$1,906,349
Conservation	$30,230,423	$10,884,863	$4,137,560	$7,429,782	$3,476,021	$4,005,708	$296,489
Transmission-Long Distance	$38,879,140	$13,998,948	$5,321,288	$9,555,392	$4,470,486	$5,151,713	$381,312
Total Retail Services	**$215,865,248**	**$116,123,153**	**$26,184,693**	**$33,844,688**	**$15,077,539**	**$13,109,719**	**$11,525,456**
Distribution	$160,595,525	$72,249,024	$20,586,070	$31,086,560	$13,398,511	$11,824,286	$11,451,074
In Service Area Transmission	$10,465,039	$4,486,728	$1,405,881	$2,407,804	$1,059,303	$1,032,548	$72,776
Stations	$27,803,120	$11,920,168	$3,735,091	$6,396,963	$2,814,316	$2,743,234	$193,348
Wires & Related Equipment	$88,365,219	$44,178,548	$11,412,462	$17,293,289	$7,618,902	$7,349,280	$512,737
Transformers	$12,815,583	$4,274,429	$2,255,921	$4,568,569	$999,048	$586,515	$131,099
Meters	$10,605,450	$7,389,151	$1,776,714	$419,935	$906,942	$112,708	$0
Streetlights	$10,541,113	$0	$0	$0	$0	$0	$10,541,113
Customer Costs	$45,799,899	$39,764,751	$4,338,956	$691,134	$733,302	$271,756	$0
Utility Discount Program	$9,469,823	$4,109,378	$1,259,667	$2,066,994	$945,726	$1,013,677	$74,382
Total	**$574,814,550**	**$245,367,590**	**$75,313,164**	**$122,064,265**	**$56,351,033**	**$60,672,601**	**$15,045,899**
Shoreline	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$20,790,533**	**$12,674,271**	**$2,402,496**	**$4,821,774**	**$891,992**		
Production	$5,529,427	$3,370,835	$638,965	$1,282,394	$237,233		
Purchased Power	$11,258,243	$6,863,221	$1,300,971	$2,611,030	$483,021		
Conservation	$1,750,962	$1,067,417	$202,336	$406,086	$75,123		
Transmission-Long Distance	$2,251,900	$1,372,798	$260,223	$522,264	$96,615		
Total Retail Services	**$14,843,717**	**$11,387,541**	**$1,280,492**	**$1,849,832**	**$325,852**		
Distribution	$10,080,408	$7,085,053	$1,006,707	$1,699,083	$289,565		
In Service Area Transmission	$663,234	$439,988	$68,751	$131,602	$22,893		
Stations	$1,762,056	$1,168,943	$182,655	$349,636	$60,822		
Wires & Related Equipment	$6,000,285	$4,332,340	$558,096	$945,191	$164,658		
Transformers	$800,782	$419,169	$110,320	$249,702	$21,591		
Meters	$854,050	$724,612	$86,885	$22,952	$19,601		
Streetlights	$0	$0	$0	$0	$0		
Customer Costs	$4,165,312	$3,899,504	$212,185	$37,775	$15,848		
Utility Discount Program	$597,998	$402,983	$61,601	$112,975	$20,439		
Total	**$35,634,250**	**$24,061,812**	**$3,682,988**	**$6,671,606**	**$1,217,844**		
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$28,727,510**	**$3,207,535**	**$1,608,251**	**$5,775,260**	**$6,035,633**	**$12,100,832**	
Production	$7,640,337	$853,072	$427,729	$1,535,982	$1,605,230	$3,218,324	
Purchased Power	$15,556,182	$1,736,907	$870,881	$3,127,350	$3,268,345	$6,552,699	
Conservation	$2,419,408	$270,136	$135,446	$486,388	$508,316	$1,019,122	
Transmission-Long Distance	$3,111,584	$347,420	$174,196	$625,540	$653,742	$1,310,686	
Total Retail Services	**$11,494,906**	**$2,881,897**	**$857,172**	**$2,215,629**	**$2,204,865**	**$3,335,342**	
Distribution	$9,469,652	$1,793,047	$673,898	$2,035,069	$1,959,332	$3,008,306	
In Service Area Transmission	$732,604	$111,350	$46,022	$157,626	$154,907	$262,698	
Stations	$1,946,354	$295,830	$122,271	$418,775	$411,552	$697,927	
Wires & Related Equipment	$5,586,034	$1,096,405	$373,594	$1,132,098	$1,114,151	$1,869,786	
Transformers	$774,325	$106,081	$73,849	$299,080	$146,096	$149,220	
Meters	$430,335	$183,381	$58,162	$27,491	$132,627	$28,675	
Streetlights	$0	$0	$0	$0	$0	$0	
Customer Costs	$1,350,522	$986,865	$142,038	$45,245	$107,234	$69,140	
Utility Discount Program	$674,731	$101,985	$41,236	$135,315	$138,298	$257,897	
Total	**$40,222,416**	**$6,089,432**	**$2,465,424**	**$7,990,889**	**$8,240,498**	**$15,436,174**	
Other Suburbs	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$34,011,211**	**$22,296,311**	**$5,050,438**	**$5,326,507**	**$1,337,954**		
Production	$9,045,584	$5,929,902	$1,343,209	$1,416,632	$355,841		
Purchased Power	$18,417,349	$12,073,635	$2,734,853	$2,884,347	$724,513		
Conservation	$2,864,397	$1,877,777	$425,344	$448,594	$112,681		
Transmission-Long Distance	$3,683,881	$2,414,997	$547,032	$576,934	$144,919		
Total Retail Services	**$25,256,760**	**$20,032,723**	**$2,691,803**	**$2,043,469**	**$488,765**		
Distribution	$16,891,414	$12,463,877	$2,116,261	$1,876,939	$434,337		
In Service Area Transmission	$1,098,260	$774,018	$144,525	$145,378	$34,339		
Stations	$2,917,816	$2,056,381	$383,970	$386,235	$91,231		
Wires & Related Equipment	$10,085,682	$7,621,362	$1,173,208	$1,044,131	$246,980		
Transformers	$1,277,530	$737,393	$231,910	$275,840	$32,386		
Meters	$1,512,125	$1,274,723	$182,647	$25,355	$29,400		
Streetlights	$0	$0	$0	$0	$0		
Customer Costs	$7,371,474	$6,859,926	$446,047	$41,729	$23,771		
Utility Discount Program	$993,873	$708,920	$129,495	$124,801	$30,657		
Total	**$59,267,971**	**$42,329,035**	**$7,742,241**	**$7,369,976**	**$1,826,720**		
Total Non-network	**$709,939,187**	**$317,847,868**	**$89,203,816**	**$144,096,736**	**$67,636,094**	**$76,108,775**	**$15,045,899**

Table 4.8: 2016 Non-network Revenue Requirements Allocated by Jurisdiction

City of Seattle	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	**$378,754,233**	**$135,316,272**	**$52,018,189**	**$93,598,160**	**$43,774,940**	**$50,607,707**	**$3,438,965**
Production	$101,421,159	$36,234,402	$13,929,204	$25,063,308	$11,721,863	$13,551,512	$920,871
Purchased Power	$202,202,942	$72,240,376	$27,770,596	$49,968,612	$23,369,829	$27,017,592	$1,835,937
Conservation	$33,017,210	$11,795,949	$4,534,591	$8,159,249	$3,816,001	$4,411,635	$299,785
Transmission-Long Distance	$42,112,922	$15,045,544	$5,783,798	$10,406,991	$4,867,248	$5,626,969	$382,372
Total Retail Services	**$222,508,706**	**$119,526,058**	**$27,057,613**	**$34,839,970**	**$15,561,247**	**$13,356,381**	**$12,167,437**
Distribution	$164,126,895	$73,530,359	$21,108,954	$31,761,591	$13,718,507	$11,917,505	$12,089,980
In Service Area Transmission	$11,004,450	$4,692,507	$1,488,980	$2,554,898	$1,117,645	$1,081,783	$68,638
Stations	$28,355,641	$12,091,386	$3,836,720	$6,583,315	$2,879,883	$2,787,476	$176,861
Wires & Related Equipment	$89,446,628	$44,693,377	$11,633,343	$17,559,041	$7,759,471	$7,340,398	$460,997
Transformers	$12,895,263	$4,277,480	$2,280,398	$4,622,485	$1,006,898	$589,191	$118,812
Meters	$11,160,240	$7,775,608	$1,869,512	$441,852	$954,610	$118,657	$0
Streetlights	$11,264,673	$0	$0	$0	$0	$0	$11,264,673
Customer Costs	$47,649,336	$41,370,535	$4,513,870	$718,970	$763,101	$282,860	$0
Utility Discount Program	$10,732,474	$4,625,164	$1,434,789	$2,359,410	$1,079,638	$1,156,016	$77,457
Total	**$601,262,939**	**$254,842,331**	**$79,075,801**	**$128,438,131**	**$59,336,187**	**$63,964,088**	**$15,606,402**
Shoreline	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$21,922,666**	**$13,261,084**	**$2,545,115**	**$5,169,092**	**$947,375**		
Production	$5,870,356	$3,550,995	$681,520	$1,384,157	$253,684		
Purchased Power	$11,703,705	$7,079,605	$1,358,743	$2,759,588	$505,769		
Conservation	$1,911,068	$1,156,011	$221,866	$450,606	$82,586		
Transmission-Long Distance	$2,437,537	$1,474,473	$282,986	$574,741	$105,337		
Total Retail Services	**$15,298,354**	**$11,713,633**	**$1,323,859**	**$1,924,087**	**$336,776**		
Distribution	$10,289,805	$7,206,024	$1,032,806	$1,754,079	$296,895		
In Service Area Transmission	$698,007	$459,869	$72,852	$141,098	$24,188		
Stations	$1,798,584	$1,184,964	$187,721	$363,573	$62,326		
Wires & Related Equipment	$6,086,823	$4,379,981	$569,189	$969,723	$167,930		
Transformers	$807,844	$419,196	$111,574	$255,283	$21,791		
Meters	$898,547	$762,015	$91,470	$24,402	$20,660		
Streetlights	$0	$0	$0	$0	$0		
Customer Costs	$4,331,413	$4,054,340	$220,852	$39,706	$16,515		
Utility Discount Program	$677,137	$453,269	$70,201	$130,302	$23,365		
Total	**$37,221,021**	**$24,974,717**	**$3,868,974**	**$7,093,179**	**$1,284,151**		
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$30,414,696**	**$3,358,996**	**$1,707,995**	**$6,101,332**	**$6,398,190**	**$12,848,183**	
Production	$8,144,315	$899,457	$457,359	$1,633,788	$1,713,279	$3,440,431	
Purchased Power	$16,237,286	$1,793,244	$911,836	$3,257,277	$3,415,758	$6,859,172	
Conservation	$2,651,346	$292,814	$148,891	$531,873	$557,751	$1,120,017	
Transmission-Long Distance	$3,381,749	$373,480	$189,909	$678,395	$711,402	$1,428,564	
Total Retail Services	**$11,791,888**	**$2,967,030**	**$888,425**	**$2,271,094**	**$2,274,448**	**$3,390,891**	
Distribution	$9,619,498	$1,825,266	$693,103	$2,070,425	$2,005,111	$3,025,592	
In Service Area Transmission	$769,915	$116,483	$48,890	$166,545	$163,356	$274,641	
Stations	$1,983,874	$300,148	$125,977	$429,143	$420,927	$707,679	
Wires & Related Equipment	$5,633,722	$1,109,437	$381,976	$1,144,612	$1,134,132	$1,863,566	
Transformers	$779,132	$106,181	$74,876	$301,323	$147,169	$149,583	
Meters	$452,855	$193,016	$61,385	$28,803	$139,527	$30,124	
Streetlights	$0	$0	$0	$0	$0	$0	
Customer Costs	$1,405,379	$1,026,953	$148,211	$46,867	$111,536	$71,812	
Utility Discount Program	$767,012	$114,812	$47,111	$153,802	$157,801	$293,487	
Total	**$42,206,584**	**$6,326,026**	**$2,596,420**	**$8,372,426**	**$8,672,637**	**$16,239,075**	
Other Suburbs	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	**$35,752,024**	**$23,356,835**	**$5,347,014**	**$5,638,563**	**$1,409,612**		
Production	$9,573,521	$6,254,391	$1,431,800	$1,509,870	$377,460		
Purchased Power	$19,086,689	$12,469,354	$2,854,574	$3,010,221	$752,540		
Conservation	$3,116,617	$2,036,089	$466,116	$491,531	$122,880		
Transmission-Long Distance	$3,975,196	$2,597,000	$594,524	$626,940	$156,732		
Total Retail Services	**$26,012,515**	**$20,631,298**	**$2,781,286**	**$2,098,838**	**$501,093**		
Distribution	$17,216,976	$12,692,017	$2,169,815	$1,913,389	$441,754		
In Service Area Transmission	$1,152,927	$809,970	$153,054	$153,913	$35,990		
Stations	$2,970,795	$2,087,085	$394,381	$396,594	$92,736		
Wires & Related Equipment	$10,217,956	$7,714,488	$1,195,806	$1,057,796	$249,865		
Transformers	$1,283,630	$738,332	$234,405	$278,469	$32,423		
Meters	$1,591,669	$1,342,142	$192,169	$26,618	$30,740		
Streetlights	$0	$0	$0	$0	$0		
Customer Costs	$7,672,807	$7,140,935	$463,986	$43,312	$24,573		
Utility Discount Program	$1,122,732	$798,346	$147,484	$142,136	$34,766		
Total	**$61,764,538**	**$43,988,133**	**$8,128,300**	**$7,737,401**	**$1,910,705**		
Total Non-network	**$742,455,082**	**$330,131,207**	**$93,669,494**	**$151,641,137**	**$71,203,680**	**$80,203,163**	**$15,606,402**

4.2. Adjustments

4.2.1. Net Wholesale Revenue Credit

City Light sells surplus energy in the wholesale market and buys wholesale energy when deficit. On an annual basis, the utility is a net seller, and the projected net wholesale revenues serve to reduce the revenue requirements. Per the 2015-2020 Strategic Plan Update, assumed net wholesale revenues (NWR) for 2015 and 2016 are $65 million and $60 million, respectively. **Tables 4.9** and **4.10** show how this NWR credit is allocated among customers in 2015 and 2016, respectively. We first calculate revenue requirements for each customer class in each jurisdiction as a percent of total revenue requirements and then multiply this percentage by the projected NWR.

Table 4.9: 2015 Net Wholesale Credit Allocation

Revenue Requirements							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$574,814,550	$245,367,590	$75,313,164	$122,064,265	$56,351,033	$60,672,601	$15,045,899
Shoreline	$35,634,250	$24,061,812	$3,682,988	$6,671,606	$1,217,844	$0	$0
Tukwila	$40,222,416	$6,089,432	$2,465,424	$7,990,889	$8,240,498	$15,436,174	$0
Other Suburbs	$59,267,971	$42,329,035	$7,742,241	$7,369,976	$1,826,720	$0	$0
Network	$140,474,073	$13,010,549	$14,858,375	$56,228,393	$56,376,756	$0	$0
Service Territory	**$850,413,261**	**$330,858,416**	**$104,062,191**	**$200,325,129**	**$124,012,850**	**$76,108,775**	**$15,045,899**
% of Service Territory Revenue Requirements							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	67.59%	28.85%	8.86%	14.35%	6.63%	7.13%	1.77%
Shoreline	4.19%	2.83%	0.43%	0.78%	0.14%	0.00%	0.00%
Tukwila	4.73%	0.72%	0.29%	0.94%	0.97%	1.82%	0.00%
Other Suburbs	6.97%	4.98%	0.91%	0.87%	0.21%	0.00%	0.00%
Network	16.52%	1.53%	1.75%	6.61%	6.63%	0.00%	0.00%
Service Territory	100.00%	38.91%	12.24%	23.56%	14.58%	8.95%	1.77%
Net Wholesale Revenue Credit							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$43,935,046	$18,754,286	$5,756,443	$9,329,790	$4,307,103	$4,637,415	$1,150,010
Shoreline	$2,723,648	$1,839,127	$281,503	$509,934	$93,084	$0	$0
Tukwila	$3,074,337	$465,436	$188,441	$610,771	$629,850	$1,179,840	$0
Other Suburbs	$4,530,054	$3,235,353	$591,766	$563,313	$139,622	$0	$0
Network	$10,736,915	$994,441	$1,135,677	$4,297,729	$4,309,069	$0	$0
Total	**$65,000,000**	**$25,288,643**	**$7,953,830**	**$15,311,536**	**$9,478,727**	**$5,817,254**	**$1,150,010**

Table 4.10: 2016 Net Wholesale Credit Allocation

Revenue Requirements							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$601,262,939	$254,842,331	$79,075,801	$128,438,131	$59,336,187	$63,964,088	$15,606,402
Shoreline	$37,221,021	$24,974,717	$3,868,974	$7,093,179	$1,284,151	$0	$0
Tukwila	$42,206,584	$6,326,026	$2,596,420	$8,372,426	$8,672,637	$16,239,075	$0
Other Suburbs	$61,764,538	$43,988,133	$8,128,300	$7,737,401	$1,910,705	$0	$0
Network	$146,024,952	$13,899,672	$15,621,985	$58,052,024	$58,451,271	$0	$0
Service Territory	**$888,480,034**	**$344,030,879**	**$109,291,479**	**$209,693,160**	**$129,654,951**	**$80,203,163**	**$15,606,402**
% of Service Territory Revenue Requirements							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	67.67%	28.68%	8.90%	14.46%	6.68%	7.20%	1.76%
Shoreline	4.19%	2.81%	0.44%	0.80%	0.14%	0.00%	0.00%
Tukwila	4.75%	0.71%	0.29%	0.94%	0.98%	1.83%	0.00%
Other Suburbs	6.95%	4.95%	0.91%	0.87%	0.22%	0.00%	0.00%
Network	16.44%	1.56%	1.76%	6.53%	6.58%	0.00%	0.00%
Service Territory	100.00%	38.72%	12.30%	23.60%	14.59%	9.03%	1.76%
Net Wholesale Revenue Credit							
	Total	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
City of Seattle	$40,603,925	$17,209,773	$5,340,073	$8,673,563	$4,007,036	$4,319,563	$1,053,917
Shoreline	$2,513,575	$1,686,569	$261,276	$479,010	$86,720	$0	$0
Tukwila	$2,850,255	$427,203	$175,339	$565,399	$585,672	$1,096,642	$0
Other Suburbs	$4,171,025	$2,970,565	$548,913	$522,515	$129,032	$0	$0
Network	$9,861,220	$938,660	$1,054,969	$3,920,315	$3,947,276	$0	$0
Total	**$60,000,000**	**$23,232,771**	**$7,380,570**	**$14,160,802**	**$8,755,737**	**$5,416,205**	**$1,053,917**

4.2.2. Franchise Agreements

City Light has franchise agreements with five suburban jurisdictions (Burien, Lake Forest Park, SeaTac, Shoreline and Tukwila), according to which their residents pay higher electric rates than the City of Seattle customers. Other suburban areas are treated similarly.

Per the terms of Shoreline's new franchise agreement signed in 2014, total revenue requirements (net of NWR credit) for each customer class are increased by 8%. Tukwila's franchise agreement calls for total energy requirements (net of NWR credit) to be increased by 8% and total distribution (retail services) requirements (net of NWR credit) to be increased by 6%. The separation of Tukwila's NWR credit between energy and distribution is based on its energy and distribution revenue requirements as a percentage of total revenue requirements before the NWR credit. Other Suburbs total revenue requirements (net of NWR credit) for each customer class are increased by 6%, per current and expected franchise renewal terms. Revenues from these rate differentials are credited to City of Seattle residential customers. **Tables 4.11** and **4.12** present calculations for these franchise-related adjustments to rates for 2015 and 2016.

Table 4.11: 2015 Franchise Adjustments

Shoreline	Total	Residential	Small	Medium	Large	High Demand
Revenue Requirement	$32,910,602	$22,222,685	$3,401,485	$6,161,672	$1,124,760	$0
Differential (8%)	$2,632,848	$1,777,815	$272,119	$492,934	$89,981	$0
Total Adjustment	**$2,632,848**	**$1,777,815**	**$272,119**	**$492,934**	**$89,981**	**$0**
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Energy	$26,531,768	$2,875,113	$1,473,664	$5,339,037	$5,585,784	$11,258,171
Total Distribution	$10,616,311	$2,748,883	$803,319	$2,041,081	$2,024,865	$2,998,164
Energy Differential (8%)	$2,122,541	$230,009	$117,893	$427,123	$446,863	$900,654
Distribution Differential (6%)	$636,979	$164,933	$48,199	$122,465	$121,492	$179,890
Total Adjustment	**$2,759,520**	**$394,942**	**$166,092**	**$549,588**	**$568,355**	**$1,080,543**
Other Suburbs	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Revenue Requirement	$54,737,917	$39,093,681	$7,150,475	$6,806,664	$1,687,097	$0
Differential (6%)	$3,284,275	$2,345,621	$429,028	$408,400	$101,226	$0
Total Adjustment	**$3,284,275**	**$2,345,621**	**$429,028**	**$408,400**	**$101,226**	**$0**
Total	**$8,676,643**	**$8,676,643**				

Table 4.12: 2016 Franchise Adjustments

Shoreline	Total	Residential	Small	Medium	Large	High Demand
Revenue Requirement	$34,707,446	$23,288,148	$3,607,698	$6,614,169	$1,197,431	$0
Differential (8%)	$2,776,596	$1,863,052	$288,616	$529,134	$95,794	$0
Total Adjustment	**$2,776,596**	**$1,863,052**	**$288,616**	**$529,134**	**$95,794**	**$0**
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Total Energy	$28,360,759	$3,051,146	$1,581,643	$5,693,897	$5,976,145	$12,057,927
Total Distribution	$10,995,570	$2,847,676	$839,438	$2,113,130	$2,110,820	$3,084,506
Energy Differential (8%)	$2,268,861	$244,092	$126,531	$455,512	$478,092	$964,634
Distribution Differential (6%)	$659,734	$170,861	$50,366	$126,788	$126,649	$185,070
Total Adjustment	**$2,928,595**	**$414,952**	**$176,898**	**$582,300**	**$604,741**	**$1,149,705**
Other Suburbs	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**
Revenue Requirement	$57,593,514	$41,017,568	$7,579,387	$7,214,886	$1,781,673	$0
Differential (6%)	$3,455,611	$2,461,054	$454,763	$432,893	$106,900	$0
Total Adjustment	**$3,455,611**	**$2,461,054**	**$454,763**	**$432,893**	**$106,900**	**$0**
Total	**$9,160,801**	**$9,160,801**				

4.2.3. Consolidation of Seattle Network and Non-network Residential and Small General Service Classes

Costs of service and allocation of revenue requirements include all network classes. However, per City policy, Residential and Small General Service customers do not have distinct network rate classes. Therefore, one of the final steps in the allocation process is to consolidate the revenue requirements and loads for the network and non-network customers for Residential and Small General Service. **Tables 4.13** and **4.14** show how 2015 and 2016 revenue requirements are broken out by functionalized category for City of Seattle Residential and Small General Service customers and one set of rates is established for all Residential and one set of rates for all Small General Service customers within the City of Seattle. Note that the franchise differential revenue credited to City of Seattle residential customers is shown near the bottom of these tables.

Table 4.13: 2015 Consolidation of City of Seattle Residential and Small General Service Revenue Requirements

	Non-network		Network		Total	
City of Seattle	**Residential**	**Small**	**Residential**	**Small**	**Residential**	**Small**
Total Energy	**$129,244,436**	**$49,128,471**	**$5,063,333**	**$7,928,182**	**$134,307,769**	**$57,056,653**
Production	$34,373,707	$13,066,154	$1,346,638	$2,108,571	$35,720,345	$15,174,724
Purchased Power	$69,986,919	$26,603,469	$2,741,836	$4,293,175	$72,728,755	$30,896,644
Conservation	$10,884,863	$4,137,560	$426,430	$667,705	$11,311,293	$4,805,266
Transmission-Long Distance	$13,998,948	$5,321,288	$548,429	$858,731	$14,547,376	$6,180,019
Total Retail Services	**$116,123,153**	**$26,184,693**	**$7,947,216**	**$6,930,193**	**$124,070,369**	**$33,114,886**
Distribution	$72,249,024	$20,586,070	$5,169,208	$6,202,574	$77,418,232	$26,788,643
In Service Area Transmission	$4,486,728	$1,405,881	$152,603	$219,434	$4,639,330	$1,625,315
Stations	$11,920,168	$3,735,091	$425,617	$612,014	$12,345,785	$4,347,104
Wires & Related Equipment	$44,178,548	$11,412,462	$3,301,039	$3,800,125	$47,479,587	$15,212,588
Transformers	$4,274,429	$2,255,921	$818,316	$1,277,929	$5,092,745	$3,533,851
Meters	$7,389,151	$1,776,714	$471,634	$293,071	$7,860,785	$2,069,785
Streetlights	$0	$0	$0	$0	$0	$0
Customer Costs	$39,764,751	$4,338,956	$2,532,712	$435,996	$42,297,463	$4,774,952
Utility Discount Program	$4,109,378	$1,259,667	$245,296	$291,623	$4,354,674	$1,551,290
Subtotal	**$245,367,590**	**$75,313,164**	**$13,010,549**	**$14,858,375**	**$258,378,138**	**$90,171,539**
Net Wholesale Revenue Credit	-$18,754,286	-$5,756,443	-$994,441	-$1,135,677	-$19,748,727	-$6,892,120
Franchise Adjustment					-$8,676,643	
Total	**$226,613,304**	**$69,556,720**	**$12,016,108**	**$13,722,698**	**$229,952,769**	**$83,279,419**

Table 4.14: 2016 Consolidation of City of Seattle Residential and Small General Service Revenue Requirements

City of Seattle	Non-network		Network		Total	
	Residential	Small	Residential	Small	Residential	Small
Total Energy	**$135,316,272**	**$52,018,189**	**$5,297,560**	**$8,373,435**	**$140,613,833**	**$60,391,623**
Production	$36,234,402	$13,929,204	$1,418,558	$2,242,202	$37,652,960	$16,171,406
Purchased Power	$72,240,376	$27,770,596	$2,828,173	$4,470,269	$75,068,549	$32,240,864
Conservation	$11,795,949	$4,534,591	$461,805	$729,939	$12,257,755	$5,264,530
Transmission-Long Distance	$15,045,544	$5,783,798	$589,025	$931,025	$15,634,570	$6,714,823
Total Retail Services	**$119,526,058**	**$27,057,613**	**$8,602,112**	**$7,248,550**	**$128,128,170**	**$34,306,163**
Distribution	$73,530,359	$21,108,954	$5,676,485	$6,460,063	$79,206,843	$27,569,017
In Service Area Transmission	$4,692,507	$1,488,980	$184,083	$241,066	$4,876,591	$1,730,047
Stations	$12,091,386	$3,836,720	$497,955	$652,097	$12,589,341	$4,488,817
Wires & Related Equipment	$44,693,377	$11,633,343	$3,675,588	$3,962,842	$48,368,965	$15,596,185
Transformers	$4,277,480	$2,280,398	$822,543	$1,295,650	$5,100,023	$3,576,048
Meters	$7,775,608	$1,869,512	$496,315	$308,408	$8,271,923	$2,177,920
Streetlights	$0	$0	$0	$0	$0	$0
Customer Costs	$41,370,535	$4,513,870	$2,635,066	$453,616	$44,005,601	$4,967,486
Utility Discount Program	$4,625,164	$1,434,789	$290,561	$334,871	$4,915,725	$1,769,661
Subtotal	**$254,842,331**	**$79,075,801**	**$13,899,672**	**$15,621,985**	**$268,742,003**	**$94,697,786**
Net Wholesale Revenue Credit	-$17,209,773	-$5,340,073	-$938,660	-$1,054,969	-$18,148,433	-$6,395,042
Franchise Adjustment					-$9,160,801	
Total	**$237,632,557**	**$73,735,728**	**$12,961,013**	**$14,567,016**	**$241,432,769**	**$88,302,744**

4.3. Final Allocation

Tables 4.15 and **4.16** summarize final allocation of the 2015 and 2016 revenue requirements by rate class.

Table 4.15: Final Allocation of 2015 Revenue Requirements

Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	$518,947,324	$172,485,887	$66,117,838	$135,318,778	$81,840,664	$59,663,714	$3,520,443
Total Retail Services	$331,465,937	$158,372,529	$37,944,353	$65,006,351	$42,172,186	$16,445,061	$11,525,456
Subtotal	$850,413,261	$330,858,416	$104,062,191	$200,325,129	$124,012,850	$76,108,775	$15,045,899
Net Wholesale Revenue Credit	-$65,000,000	-$25,288,643	-$7,953,830	-$15,311,536	-$9,478,727	-$5,817,254	-$1,150,010
Franchise Adjustment	$0	-$4,158,266	$867,240	$1,450,921	$759,561	$1,080,543	$0
Total	**$785,413,261**	**$301,411,508**	**$96,975,601**	**$186,464,514**	**$115,293,684**	**$71,372,064**	**$13,895,889**
Load (MWh)	9,567,320	3,157,663	1,207,275	2,492,299	1,517,275	1,124,315	68,493
Average Rate ($/MWh)	**$82.09**	**$95.45**	**$80.33**	**$74.82**	**$75.99**	**$63.48**	**$202.88**
City of Seattle	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$371,940,818	$134,307,769	$57,056,653	$88,219,577	$41,273,494	$47,562,882	$3,520,443
Total Retail Services	$230,742,656	$124,070,369	$33,114,886	$33,844,688	$15,077,539	$13,109,719	$11,525,456
Subtotal	$602,683,474	$258,378,138	$90,171,539	$122,064,265	$56,351,033	$60,672,601	$15,045,899
Net Wholesale Revenue Credit	-$46,065,163	-$19,748,727	-$6,892,120	-$9,329,790	-$4,307,103	-$4,637,415	-$1,150,010
Franchise Adjustment	-$8,676,643	-$8,676,643					
Total	**$547,941,667**	**$229,952,769**	**$83,279,419**	**$112,734,475**	**$52,043,930**	**$56,035,186**	**$13,895,889**
Load (MWh)	6,855,189	2,458,768	1,041,847	1,623,473	766,322	896,284	68,493
Average Rate ($/MWh)	**$79.93**	**$93.52**	**$79.93**	**$69.44**	**$67.91**	**$62.52**	**$202.88**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$63,477,252			$31,175,661	$32,301,591		
Total Retail Services	$49,127,897			$25,052,732	$24,075,165		
Subtotal	$112,605,149			$56,228,393	$56,376,756		
Net Wholesale Revenue Credit	-$8,606,797			-$4,297,729	-$4,309,069		
Franchise Adjustment							
Total	**$103,998,352**			**$51,930,664**	**$52,067,688**		
Load (MWh)	1,173,277			575,791	597,486		
Average Rate ($/MWh)	**$88.64**			**$90.19**	**$87.14**		
Shoreline	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$20,790,533	$12,674,271	$2,402,496	$4,821,774	$891,992		
Total Retail Services	$14,843,717	$11,387,541	$1,280,492	$1,849,832	$325,852		
Subtotal	$35,634,250	$24,061,812	$3,682,988	$6,671,606	$1,217,844		
Net Wholesale Revenue Credit	-$2,723,648	-$1,839,127	-$281,503	-$509,934	-$93,084		
Franchise Adjustment	$2,632,848	$1,777,815	$272,119	$492,934	$89,981		
Total	**$35,543,450**	**$24,000,500**	**$3,673,604**	**$6,654,606**	**$1,214,740**		
Load (MWh)	381,174	232,017	43,862	88,733	16,562		
Average Rate ($/MWh)	**$93.25**	**$103.44**	**$83.75**	**$75.00**	**$73.35**		
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$28,727,510	$3,207,535	$1,608,251	$5,775,260	$6,035,633	$12,100,832	
Total Retail Services	$11,494,906	$2,881,897	$857,172	$2,215,629	$2,204,865	$3,335,342	
Subtotal	$40,222,416	$6,089,432	$2,465,424	$7,990,889	$8,240,498	$15,436,174	
Net Wholesale Revenue Credit	-$3,074,337	-$465,436	-$188,441	-$610,771	-$629,850	-$1,179,840	
Franchise Adjustment	$2,759,520	$394,942	$166,092	$549,588	$568,355	$1,080,543	
Total	**$39,907,599**	**$6,018,938**	**$2,443,075**	**$7,929,705**	**$8,179,003**	**$15,336,878**	
Load (MWh)	534,453	58,718	29,361	106,280	112,063	228,030	
Average Rate ($/MWh)	**$74.67**	**$102.51**	**$83.21**	**$74.61**	**$72.99**	**$67.26**	
Other Suburbs	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$34,011,211	$22,296,311	$5,050,438	$5,326,507	$1,337,954		
Total Retail Services	$25,256,760	$20,032,723	$2,691,803	$2,043,469	$488,765		
Subtotal	$59,267,971	$42,329,035	$7,742,241	$7,369,976	$1,826,720		
Net Wholesale Revenue Credit	-$4,530,054	-$3,235,353	-$591,766	-$563,313	-$139,622		
Franchise Adjustment	$3,284,275	$2,345,621	$429,028	$408,400	$101,226		
Total	**$58,022,192**	**$41,439,302**	**$7,579,503**	**$7,215,064**	**$1,788,323**		
Load (MWh)	623,228	408,160	92,205	98,022	24,842		
Average Rate ($/MWh)	**$93.10**	**$101.53**	**$82.20**	**$73.61**	**$71.99**		

Table 4.16: Final Allocation of 2016 Revenue Requirements

Service Territory	Total	Residential	Small	Medium	Large	High Demand	Lights
Total Energy	$547,683,068	$180,590,747	$69,991,747	$143,492,281	$86,713,437	$63,455,891	$3,438,965
Total Retail Services	$340,796,967	$163,440,131	$39,299,732	$66,200,880	$42,941,515	$16,747,272	$12,167,437
Subtotal	$888,480,034	$344,030,879	$109,291,479	$209,693,160	$129,654,951	$80,203,163	$15,606,402
Net Wholesale Revenue Credit	-$60,000,000	-$23,232,771	-$7,380,570	-$14,160,802	-$8,755,737	-$5,416,205	-$1,053,917
Franchise Adjustment	$0	-$4,421,743	$920,277	$1,544,326	$807,436	$1,149,705	$0
Total	**$828,480,034**	**$316,376,365**	**$102,831,186**	**$197,076,685**	**$121,706,651**	**$75,936,663**	**$14,552,485**
Load (MWh)	9,611,431	3,156,805	1,218,984	2,517,689	1,528,115	1,127,827	62,011
Average Rate ($/MWh)	**$86.20**	**$100.22**	**$84.36**	**$78.28**	**$79.64**	**$67.33**	**$234.67**
City of Seattle	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$392,425,228	$140,613,833	$60,391,623	$93,598,160	$43,774,940	$50,607,707	$3,438,965
Total Retail Services	$238,359,368	$128,128,170	$34,306,163	$34,839,970	$15,561,247	$13,356,381	$12,167,437
Subtotal	$630,784,596	$268,742,003	$94,697,786	$128,438,131	$59,336,187	$63,964,088	$15,606,402
Net Wholesale Revenue Credit	-$42,597,553	-$18,148,433	-$6,395,042	-$8,673,563	-$4,007,036	-$4,319,563	-$1,053,917
Franchise Adjustment	-$9,160,801	-$9,160,801					
Total	**$579,026,241**	**$241,432,769**	**$88,302,744**	**$119,764,567**	**$55,329,151**	**$59,644,525**	**$14,552,485**
Load (MWh)	6,883,884	2,458,021	1,051,825	1,640,986	771,570	899,471	62,011
Average Rate ($/MWh)	**$84.11**	**$98.22**	**$83.95**	**$72.98**	**$71.71**	**$66.31**	**$234.67**
Network	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$67,168,453			$32,985,133	$34,183,320		
Total Retail Services	$49,334,841			$25,066,890	$24,267,951		
Subtotal	$116,503,295			$58,052,024	$58,451,271		
Net Wholesale Revenue Credit	-$7,867,591			-$3,920,315	-$3,947,276		
Franchise Adjustment	$0						
Total	**$108,635,704**			**$54,131,709**	**$54,503,995**		
Load (MWh)	1,182,478			580,250	602,227		
Average Rate ($/MWh)	**$91.87**			**$93.29**	**$90.50**		
Shoreline	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$21,922,666	$13,261,084	$2,545,115	$5,169,092	$947,375		
Total Retail Services	$15,298,354	$11,713,633	$1,323,859	$1,924,087	$336,776		
Subtotal	$37,221,021	$24,974,717	$3,868,974	$7,093,179	$1,284,151		
Net Wholesale Revenue Credit	-$2,513,575	-$1,686,569	-$261,276	-$479,010	-$86,720		
Franchise Adjustment	$2,776,596	$1,863,052	$288,616	$529,134	$95,794		
Total	**$37,484,042**	**$25,151,200**	**$3,896,314**	**$7,143,303**	**$1,293,225**		
Load (MWh)	383,440	231,800	44,316	90,626	16,698		
Average Rate ($/MWh)	**$97.76**	**$108.50**	**$87.92**	**$78.82**	**$77.45**		
Tukwila	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$30,414,696	$3,358,996	$1,707,995	$6,101,332	$6,398,190	$12,848,183	
Total Retail Services	$11,791,888	$2,967,030	$888,425	$2,271,094	$2,274,448	$3,390,891	
Subtotal	$42,206,584	$6,326,026	$2,596,420	$8,372,426	$8,672,637	$16,239,075	
Net Wholesale Revenue Credit	-$2,850,255	-$427,203	-$175,339	-$565,399	-$585,672	-$1,096,642	
Franchise Adjustment	$2,928,595	$414,952	$176,898	$582,300	$604,741	$1,149,705	
Total	**$42,284,924**	**$6,313,775**	**$2,597,978**	**$8,389,327**	**$8,691,706**	**$16,292,137**	
Load (MWh)	536,553	58,714	29,740	106,970	112,773	228,356	
Average Rate ($/MWh)	**$78.81**	**$107.53**	**$87.36**	**$78.43**	**$77.07**	**$71.35**	
Other Suburbs	**Total**	**Residential**	**Small**	**Medium**	**Large**	**High Demand**	**Lights**
Total Energy	$35,752,024	$23,356,835	$5,347,014	$5,638,563	$1,409,612		
Total Retail Services	$26,012,515	$20,631,298	$2,781,286	$2,098,838	$501,093		
Subtotal	$61,764,538	$43,988,133	$8,128,300	$7,737,401	$1,910,705		
Net Wholesale Revenue Credit	-$4,171,025	-$2,970,565	-$548,913	-$522,515	-$129,032		
Franchise Adjustment	$3,455,611	$2,461,054	$454,763	$432,893	$106,900		
Total	**$61,049,124**	**$43,478,622**	**$8,034,150**	**$7,647,779**	**$1,888,574**		
Load (MWh)	625,075	408,270	93,103	98,857	24,846		
Average Rate ($/MWh)	**$97.67**	**$106.49**	**$86.29**	**$77.36**	**$76.01**		

4.4. Average Rate Increases in 2015 and 2016 by Rate Class

Tables 4.17-4.19 present the average rates by rate class for 2014-2016. Average rates are derived by dividing each rate class' revenue requirement by its load. **Tables 4.20** and **4.21** show average rate increases for each rate class in 2015 and 2016.

Table 4.17: 2014 Average Rates by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	$78.77	$91.95	$76.67	$72.03	$73.27	$60.12	$182.26
City of Seattle	$76.50	$90.40	$76.40	$66.52	$64.34	$58.87	$182.26
Network	$86.78	$0.00	$0.00	$87.81	$85.79		
Shoreline	$89.51	$99.56	$79.30	$71.97	$69.67		
Tukwila	$71.58	$97.42	$79.30	$71.69	$69.25	$65.02	
Other Suburbs	$88.35	$96.18	$77.60	$70.95	$68.15		

Table 4.18: 2015 Average Rates by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	$82.09	$95.45	$80.33	$74.82	$75.99	$63.48	$202.88
City of Seattle	$79.93	$93.52	$79.93	$69.44	$67.91	$62.52	$202.88
Network	$88.64			$90.19	$87.14		
Shoreline	$93.25	$103.44	$83.75	$75.00	$73.35		
Tukwila	$74.67	$102.51	$83.21	$74.61	$72.99	$67.26	
Other Suburbs	$93.10	$101.53	$82.20	$73.61	$71.99		

Table 4.19: 2016 Average Rates by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	$86.20	$100.22	$84.36	$78.28	$79.64	$67.33	$234.67
City of Seattle	$84.11	$98.22	$83.95	$72.98	$71.71	$66.31	$234.67
Network	$91.87			$93.29	$90.50		
Shoreline	$97.76	$108.50	$87.92	$78.82	$77.45		
Tukwila	$78.81	$107.53	$87.36	$78.43	$77.07	$71.35	
Other Suburbs	$97.67	$106.49	$86.29	$77.36	$76.01		

Table 4.20: 2015 Average Rate Increases by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	4.2%	3.8%	4.8%	3.9%	3.7%	5.6%	11.3%
City of Seattle	4.5%	3.5%	4.6%	4.4%	5.6%	6.2%	11.3%
Network	2.1%			2.7%	1.6%		
Shoreline	4.2%	3.9%	5.6%	4.2%	5.3%		
Tukwila	4.3%	5.2%	4.9%	4.1%	5.4%	3.4%	
Other Suburbs	5.4%	5.6%	5.9%	3.7%	5.6%		

Table 4.21: 2016 Average Rate Increases by Rate Class

	Total	Residential	Small	Medium	Large	High Demand	Lights
All areas	4.9%	5.0%	5.0%	4.6%	4.8%	6.1%	15.7%
City of Seattle	5.2%	5.0%	5.0%	5.1%	5.6%	6.1%	15.7%
Network	3.6%			3.4%	3.9%		
Shoreline	4.8%	4.9%	5.0%	5.1%	5.6%		
Tukwila	5.5%	4.9%	5.0%	5.1%	5.6%	6.1%	
Other Suburbs	4.9%	4.9%	5.0%	5.1%	5.6%		

Appendix A

The capital investments in generation, transmission, and distribution equipment and facilities provide service for an extended period of time. Instead of charging all the capital costs in the first year of operation, the costs are spread (or annualized) over the economic life of the capital asset. The process of converting the total initial cost of an asset to a series of annual costs is referred to as annualization (the calculation of annual carrying charges). The formula used in the calculation of the annual charges is shown below.[7]

$$AC = k\left[\frac{r(1+r)^n}{(1+r)^n - 1}\right]$$

where: AC = annualized cost r = real discount rate
k = investment (initial capital cost) n = asset life in years

This formula assumes that the annual costs occur at the end of each year. If costs are assumed to occur at the beginning of each year, they must be divided by $(1+r)$. We define annualization factor (AF) for the costs incurred at the end of each year as:

$$AF_{end\ year} = \left[\frac{r(1+r)^n}{(1+r)^n - 1}\right]$$

And we define the annualization factor (AF) for the costs incurred at the beginning of each year as:

$$AF_{beg\ year} = \left[\frac{r(1+r)^{n-1}}{(1+r)^n - 1}\right]$$

In our analysis we assume that the costs are incurred in the mid-year and compute the annualization factors as an average of $AF_{end\ year}$ and $AF_{beg\ year}$, except for meters and service drops where we assume costs incur at year-end and use annualization factor $AF_{end\ year}$. The table below shows the asset lives assumed for the equipment and facilities used in this study and the corresponding annualization factors based on a three percent interest rate.[8]

Assumed Asset Lives and Annualization Factors

Functional Category	Rate Discount	Years of Useful Life	Annualization Factor
In-Service Area Transmission	0.03	45	0.04019
Substations	0.03	32	0.04833
Non-network Wires and Related Equipment	0.03	45	0.04019
Network Wires and Related Equipment	0.03	30	0.05027
Transformers	0.03	30	0.05027
Meters	0.03	18	0.07271
Service Drops	0.03	40	0.04326

[7] Detailed derivation of the annualization formula is shown in Appendix C of the 1989/90 COSACAR and a similar derivation is presented in Appendix E of the 1983 Energy Resource Report Users' Guide.
[8] The asset lives are based on a study prepared for City Light by EBASCO Consulting Service (Seattle City Light: Depreciation Study of Electric Plant in Service at December 31, 1980).

Appendix B

This table illustrates how 2015 rates were calculated for the High Demand City customer class by aggregating data from the relevant sections of the COSACAR and Revenue Requirements Analysis.

Example: Average Rate for High Demand-City Customer Class for 2015								
		A	B	C	D	E	F	G
	MC Table	HD MC	Total MC[2,3]	MC Share (A/B)	Total Op. Cost Rev Req (Table 4.1)	HD Share of RR (C x D)	HD-City Load Share (Table 4.5)	HD-City Share of RR (E x F)
Energy	Table 3.16	$ 51,239,470	$ 445,674,331	11.497%	$ 518,947,324	$ 59,663,714	79.7183%	$ 47,562,882
In Service Area Transmission	Table 3.20	$ 4,198,001	$ 48,815,299	8.600%	$ 15,061,416	$ 1,295,246	79.7183%	$ 1,032,548
Stations	Table 3.24	$ 2,842,635	$ 33,284,536	8.540%	$ 40,292,713	$ 3,441,161	79.7183%	$ 2,743,234
Wires and Related Equipment[1]	Table 3.32	$ 15,167,190	$ 181,033,029	8.378%	$ 110,037,220	$ 9,219,066	79.7183%	$ 7,349,280
Transformers [1]	Table 3.42	$ 419,798	$ 8,940,033	4.696%	$ 15,668,220	$ 735,735	79.7183%	$ 586,515
Meters	Table 3.43	$ 55,208	$ 5,836,707	0.946%	$ 14,947,160	$ 141,383	79.7183%	$ 112,708
Customer Costs	Table 3.63	$ 224,882	$ 41,143,293	0.547%	$ 62,368,476	$ 340,896	79.7183%	$ 271,756
Low Income Assistance[3]	Table 3.71	$ 74,147,184	$ 846,229,772	8.762%	$ 14,512,272	$ 1,271,574	79.7183%	$ 1,013,677
Total Revenue Requirement before NWR credit								$ 60,672,601
Less NWR credit (Table 4.9)[4]								(4,637,415)
Total Class 2015 Revenue Requirement								$ 56,035,186
2015 Class Load in MWh (Table 4.3)								896,284
Average rate in $/MWh (class rev req / class load)								$ 62.5194
Average rate in $/kWh								$ 0.06252

(1) The Operating Cost Revenue Requirement from Table 4.1 for these items equals the grand total less the Downtown network portion of Network revenue requirements

(2) Total Marginal Cost for just Non-network for Wires and Related Equipment and Transformers

(3) Marginal Cost Share for Low Income Assistance is based on share of total overall Marginal Costs

(4) Net Wholesale Revenue Credits are allocated based on share of Revenue Requirements allocated by Marginal Cost Shares.

The High Demand Share for Seattle is from Table 4.9 (7.13%)